BABCOCK AND WILCOX
CROSS TRAINING MANUAL

CHAPTER 7 Incore Monitoring System

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7.0 INCORE MONITORING SYSTEM

Learning Objectives:

1. List the purposes of the incore monitoring system.

2. Explain the operation of the self-powered neutron detectors.

3. Describe the construction of the detector assembly.

4. List the outputs provided by the detector assembly components.

7.1 Introduction

The incore monitoring system continuously monitors the core neutron level to provide information on axial flux shape and quadrant power tilt. The system consists of 65 strings of self-powered neutron detectors (SPNDs) installed in preselected core locations. In addition to sensing neutrons, the incore system also provides fuel assembly exit temperature measurements.

7.2 Neutron Detection

When the element rhodium is bombarded with a neutron flux, it becomes radioactive and will decay by emitting beta particles. The reaction takes place as follows:

$$ {}^{103}_{45}\mathrm{Rh} + {}^{1}_{0}\mathrm{n} \Rightarrow {}^{104}_{45}\mathrm{Rh} \Rightarrow {}^{104}_{46}\mathrm{Pd} + {}^{0}_{-1}\beta + \mathrm{Energy} $$

Furthermore, if the rhodium is insulated from electrical ground, then the emission of the beta particles (electrons) will represent a charge deficiency that is proportional to the number of neutron interactions. A method of measuring this charge exists when the rhodium detector material is connected to ground and the flow of electrons required to replace the emitted beta particles is measured. A simplified version of the circuit needed to accomplish this function is shown in Figure 7-1. Since no external source of detector power is required, the neutron detector is self-powered. The neutron detector response time is proportional to the decay of the Rh-104 isotope. The decay scheme for rhodium involves two half-lives and is illustrated in Figure 7-2. The majority (~93%) of the rhodium-neutron reactions result in an isomer of Rh-104 which decays to palladium by beta emission with a 42-second half-life. A small number of the reactions (~7%) result in an isomer of Rh-104 which requires additional decay by gamma emission, with a 4.4-minute half-life. As previously stated, these two half-lives affect the detector response time and are of particular interest during changing neutron flux levels. As seen in Figure 7-3, approximately 5 minutes are required for the detector's output to reach the new equilibrium output if a step change in power (flux) level occurs. This long time period precludes the use of the incore detector's output in core protection systems.

7.3 System Description

The arrangement of the incore monitoring system is shown in Figure 7-4. The system consists of 65 incore detector assemblies, with each assembly consisting of 7 neutron detectors, a background wire, and a thermocouple. The incore detector assemblies are inserted into the fuel assembly instrument tubes at preselected core locations. These locations are chosen to provide the necessary quadrant symmetry. The seven individual rhodium neutron detectors are arranged in the vertical direction so that the detectors are positioned between fuel assembly spacer grids. This arrangement provides 455 (65 x 7) flux measurements.

The installation of the incore detectors is illustrated in Figure 7-5. The incore detectors are inserted into the preselected core locations following initial core loading or subsequent refuelings when the reactor coolant system is depressurized. This is accomplished by physically pushing the detectors through the conduits that lead from the incore instrument tank to the bottom of the reactor vessel. Guide tubes that are located inside the reactor vessel provide the mechanical interface between the conduits and the fuel assembly guide tubes.

The mechanical portion of the incore instrument system terminates at closure assemblies located in the incore instrument tank. The required electrical connections are also made at the closure assemblies. The conduit and closure assemblies are a part of the reactor coolant pressure boundary and are designed for 2500 psig.

7.4 Component Description

7.4.1 Detector Assembly

Each incore detector assembly (Figure 7-6) consists of seven neutron detectors, a background detector, a chromel-alumel thermocouple, and a spacer tube enclosed in a solid inconel sheath. Aluminum oxide insulation separates the rhodium emitter from ground.

The use of rhodium neutron detectors permits the manufacture of nearly identical units. However, each detector consists of a controlled mass of material that is swaged during manufacturing until the correct diameter for the detector is obtained. This swaging procedure results in detectors with slightly different lengths and surface areas, which gives each detector a different neutron sensitivity. This is corrected by x-raying each detector assembly and calculating a sensitivity correction factor for each detector. The sensitivity correction becomes a part of the computer signal processing program.

In addition to sensitivity corrections, the SPND signal is also corrected for background, burnup, and leakage. The background correction is necessary because of the gamma reactions that occur in the rhodium detector and leadwire. These reactions also cause beta emmissions; therefore, a portion of the detector's current flow is due to gammas rays. To compensate for this additional signal, a background detector is installed in each incore detector assembly. The background detector consists of the same material as the detector with the exception of the rhodium, and is of the same length as the detectors and leadwire. Because the background detector is located in the same assembly, it is subject to the same gamma flux; therefore, its output current represents the same gamma current that is present in the neutron detector signal. The plant computer receives the background signal and corrects the SPND output for gamma interactions. The burnup correction is required because of rhodium depletion. The plant computer stores detector exposure history and uses this information to correct the output of each SPND. The leakage correction is also performed by the plant computer and compensates the detector's output for any signal loss resulting from changes in the resistances of detector circuit components.

7.4.2 High-Pressure Closure Assembly

The high-pressure closure assembly, shown in Figure 7-7, provides the final pressure barrier for the incore monitoring system. The closure assembly consists of a plug, O-rings, and a nut ring assembly. The silver-plated O-rings surround the seal assembly and are deformed to form a seal by tightening the nut ring.

7.4.3 Incore Instrument Tank

To facilitate plant refueling operations, the incore instruments must be withdrawn from the fuel assembly instrument tubes. This evolution is performed, after depressurization, by disassembly of the high-pressure closure assemblies; the incore detector assemblies are then manually retracted until they are about 25 ft inside the incore instrument conduit. Essentially zero exposure occurs during this evolution because the irradiated portion of the detector remains within the conduit. However, if replacement of a detector is required, shielding must be provided. The incore instrument tank can be flooded from the spent fuel system to provide shielding, and the malfunctioning detector is withdrawn from the system. The defective detector is cut into small pieces by a specifically designed cutting tool and is disposed of as solid waste.

7.5 Incore Detector Outputs

The incore neutron monitoring system supplies signals to multipoint recorders and the plant computer (Figure 7-8). Each recorder displays selected incore detector power levels. A calibrating potentiometer is used to compensate each recorder input signal for detector burnup.

The plant computer uses the incore detector neutron signals to calculate the nuclear heat flux hot channel factor (F_Q), the nuclear enthalpy rise hot channel factor ($F^N_{\Delta H}$), the axial flux distribution (offset), and the radial flux distribution (quadrant power tilt).

The hot channel factors (F_Q and $F^N_{\Delta H}$) are calculated when some other power distribution technical specification is not satisfied.

The calculation of axial flux distribution is performed in the plant computer software, and if the offset of the core ([% upper-half power] - [% lower-half power]) exceeds the allowable technical specification limit, an alarm is generated. The calculation of offset also requires a minimum number of incore detector assemblies. For this calculation, technical specifications require the following:

1. There must be three detector assemblies with three operable neutron detectors per string.

2. One of the operable detectors must be located at core midplane, one detector in the upper half of the core, and one detector in the lower half of the core.

3. The axial planes in each core half must be symmetrical about the core midplane.

4. The three detectors need not have radial symmetry.

Figure 7-9 illustrates the minimum acceptable incore neutron detector locations for the calculation of axial flux distribution.

Quadrant power tilt is defined by the following equation:

$$\text{QPT} = 100\% \left[\frac{\text{power in any quadrant}}{\text{average quadrant power}} - 1 \right]$$

Again, the plant computer calculates quadrant power tilt, and an alarm will be generated if the quadrant power tilt exceeds allowable technical specification limits. The specifications also require a specific set of minimum incore detector strings as follows:

1. Two sets of four detectors shall lie in each core half (eight detectors/core half).

2. Each set of detectors shall lie in the same axial

plane. The two sets in each core half may lie in the same axial plane.

3. Detectors in the same plane shall have quarter core radial symmetry.

4. 75% of each core quadrant's detectors must be operable.

Figure 7-10 shows a combination of detectors that satisfies requirements (1) through (3). In summary, 75% of each quadrant's incore detectors must be operable for quadrant tilt power calculations. A specific set of 9 detectors must be available for axial flux distribution calculations, and a specific set of 16 detectors are required for radial flux distribution calculations.

7.6 Temperature Measurement

A chromel-alumel thermocouple, located at the top of each incore detector assembly, provides fuel exit temperature data. These data are used in the plant computer to generate a gross power distribution core map that provides an indication of core conditions to the operator. In recent years, use of thermocouple information has been incorporated into the plant emergency procedures. Thermocouple indications are used to determine proper natural circulation response and the degree of inadequate core cooling, if any.

7.7 Summary

The incore monitoring system provides continuous information pertaining to axial and radial flux distributions. These data are used to generate alarms if the allowable values of these parameters are exceeded. In addition, fuel assembly exit temperatures are measured to provide an indication of core power distribution.

$$ {}^{103}_{45}\mathrm{RH} + {}^{1}_{0}\mathrm{n} \longrightarrow {}^{104}_{45}\mathrm{RH} \longrightarrow {}^{104}_{46}\mathrm{Pd} + {}^{0}_{-1}\beta + \mathrm{ENERGY} $$

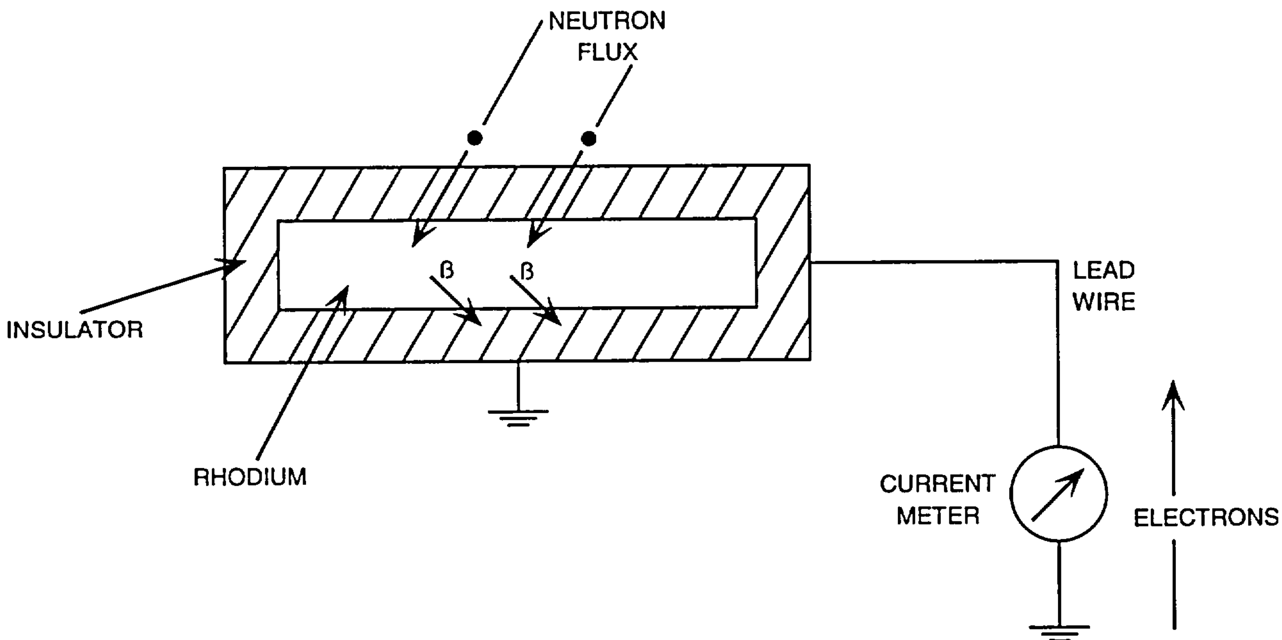


Figure 7-1 Self-Powered Neutron Detector

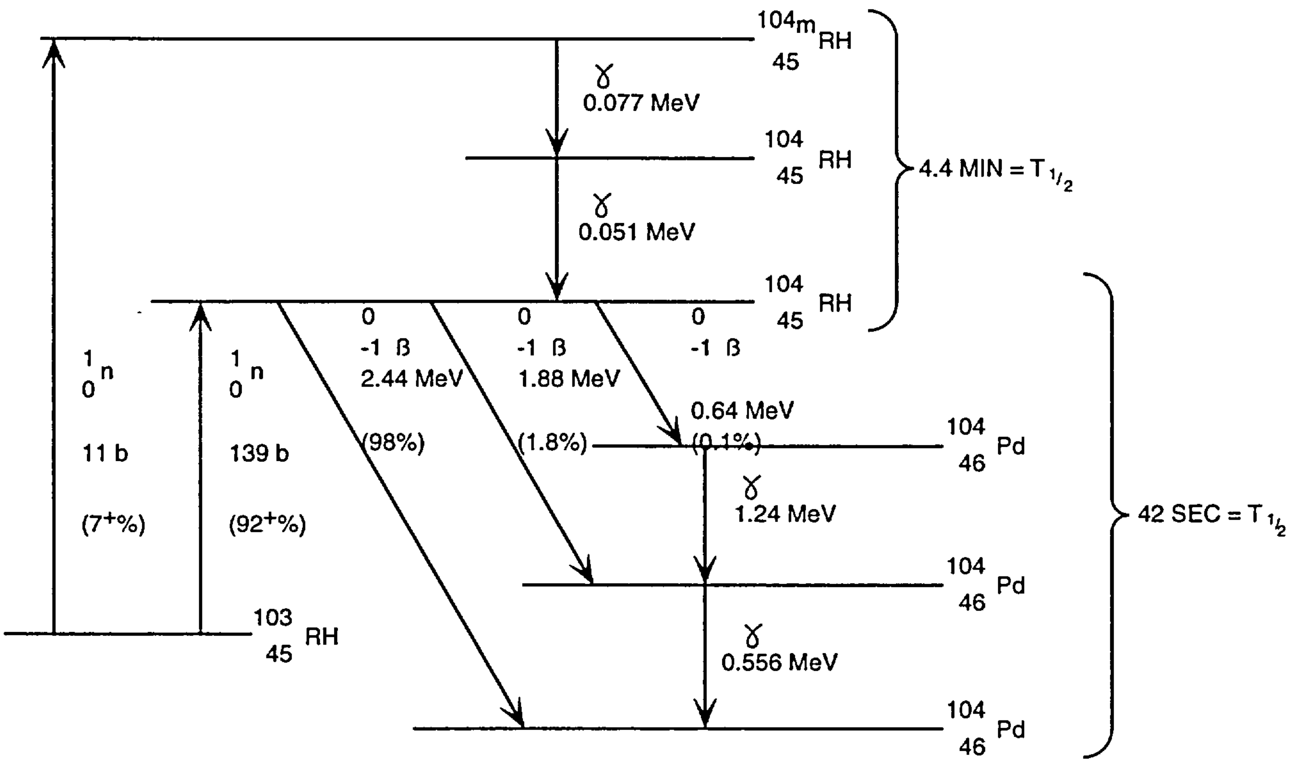


Figure 7-2 Rhodium Decay Scheme

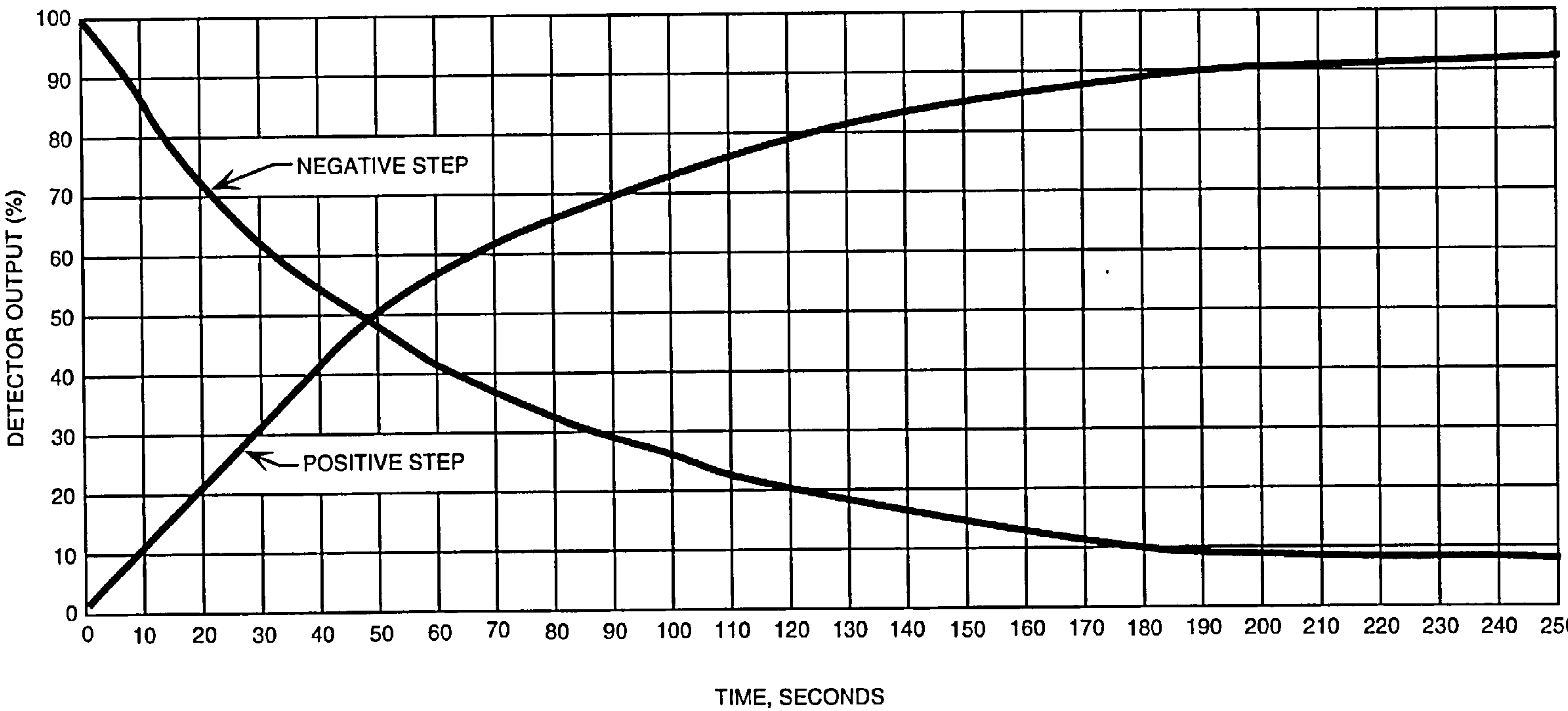
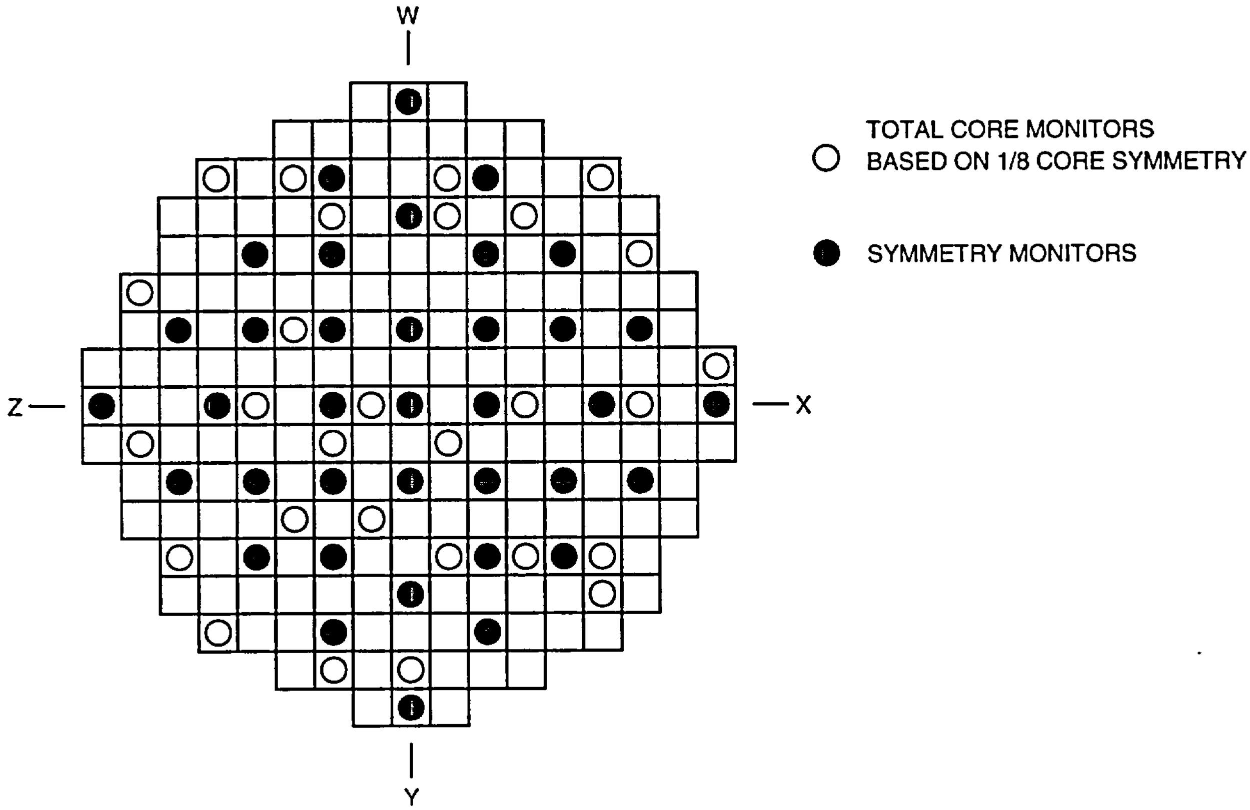


Figure 7-3 Response of Rhodium Detectors



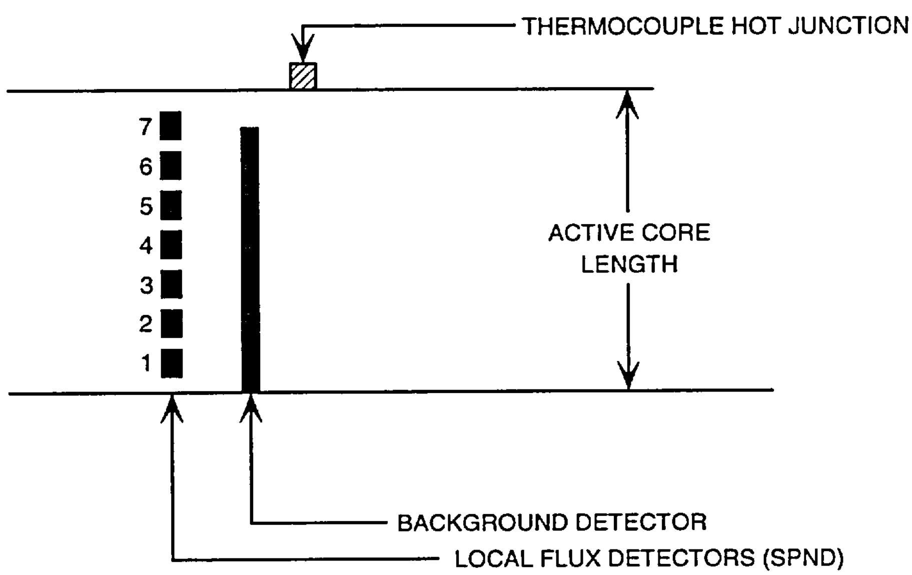


Figure 7-4 Incore Detector Arrangement

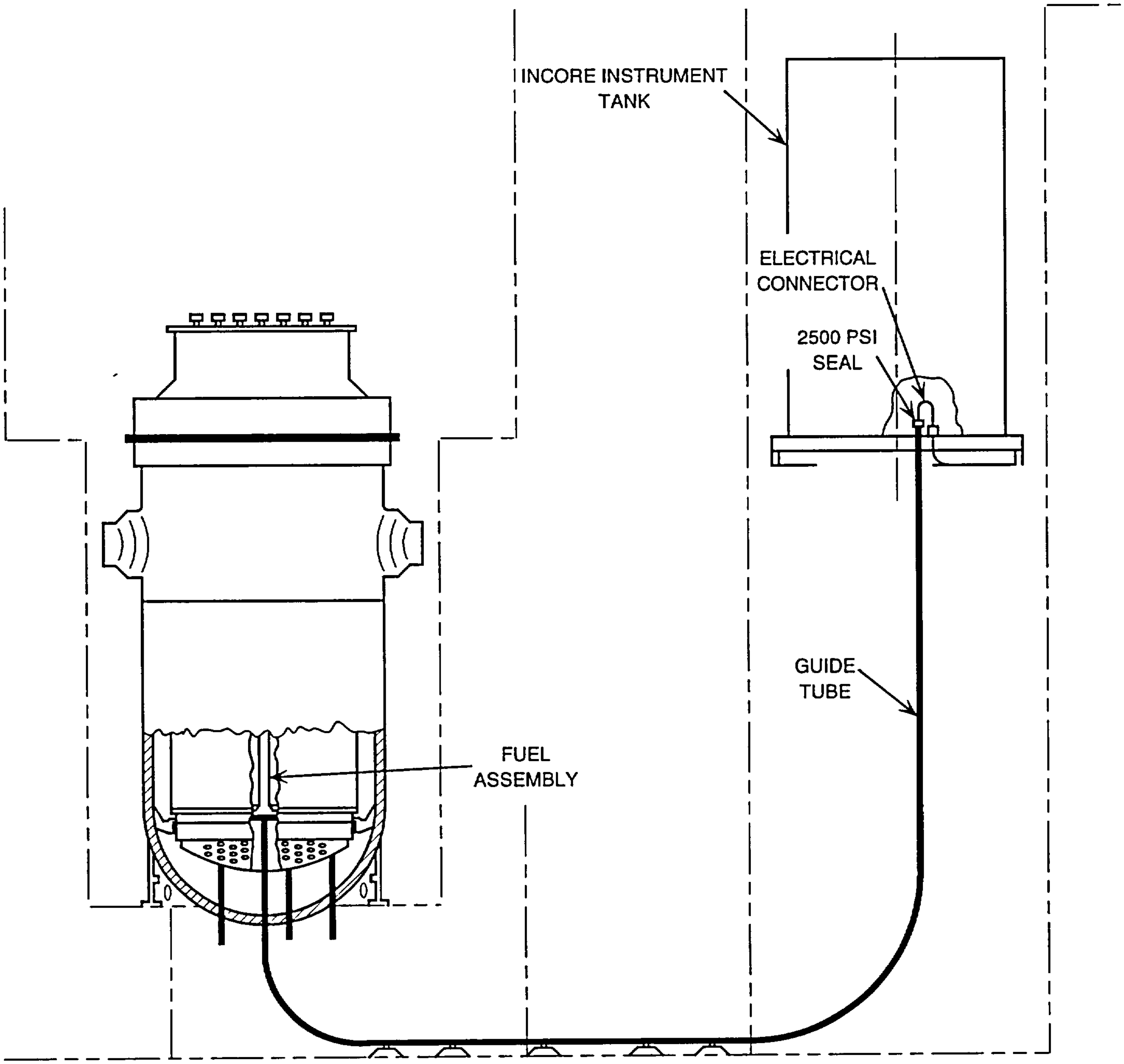


Figure 7-5 Incore Detector Assembly Installation

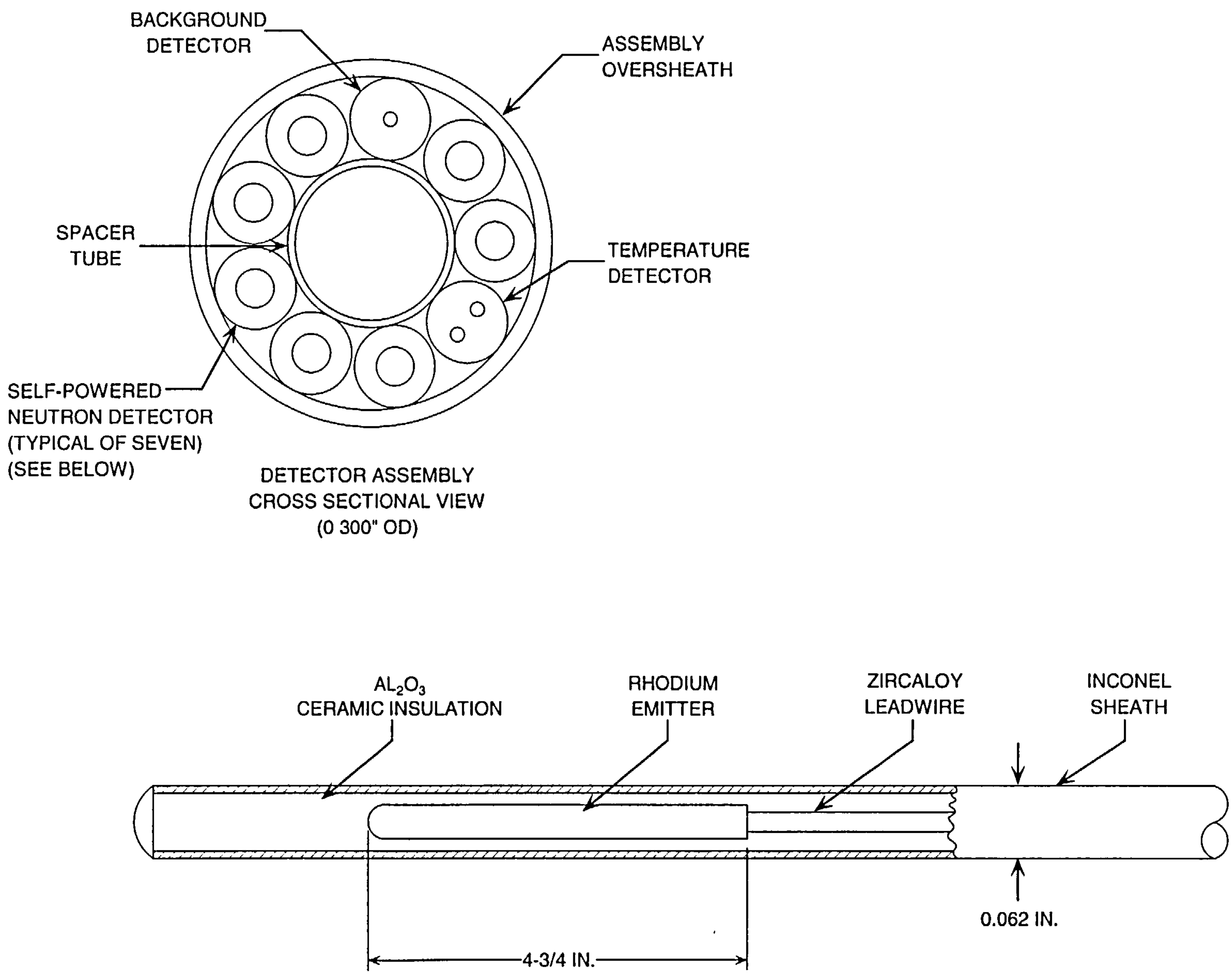


Figure 7-6 Incore Instrument Assembly

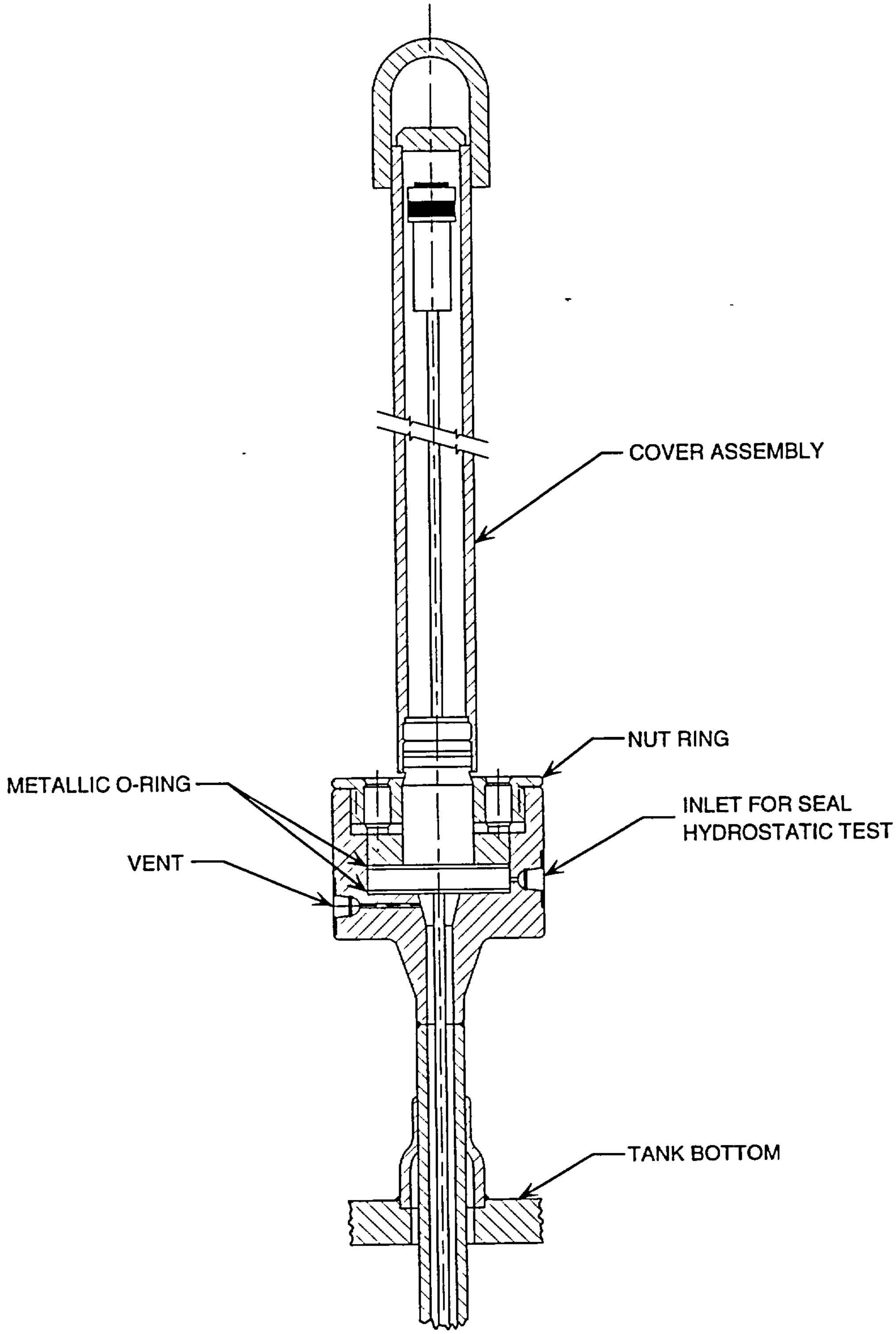


Figure 7-7 High Pressure Closure Assembly

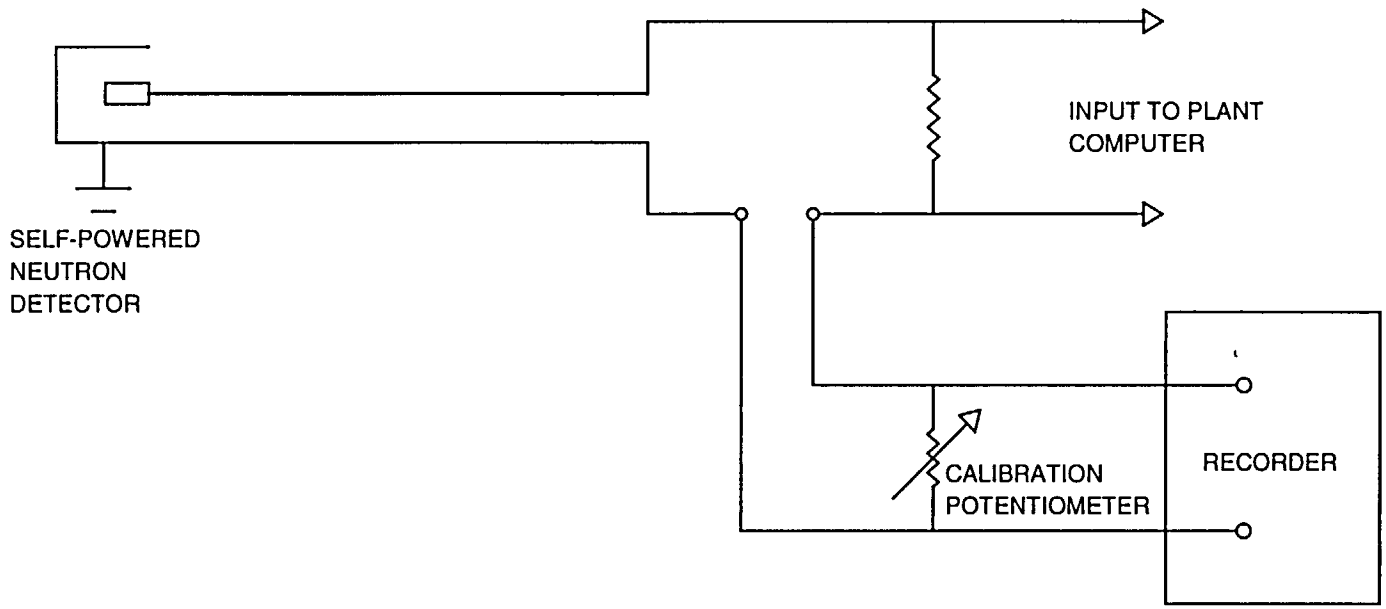


Figure 7-8 Self-Powered Neutron Detector Outputs

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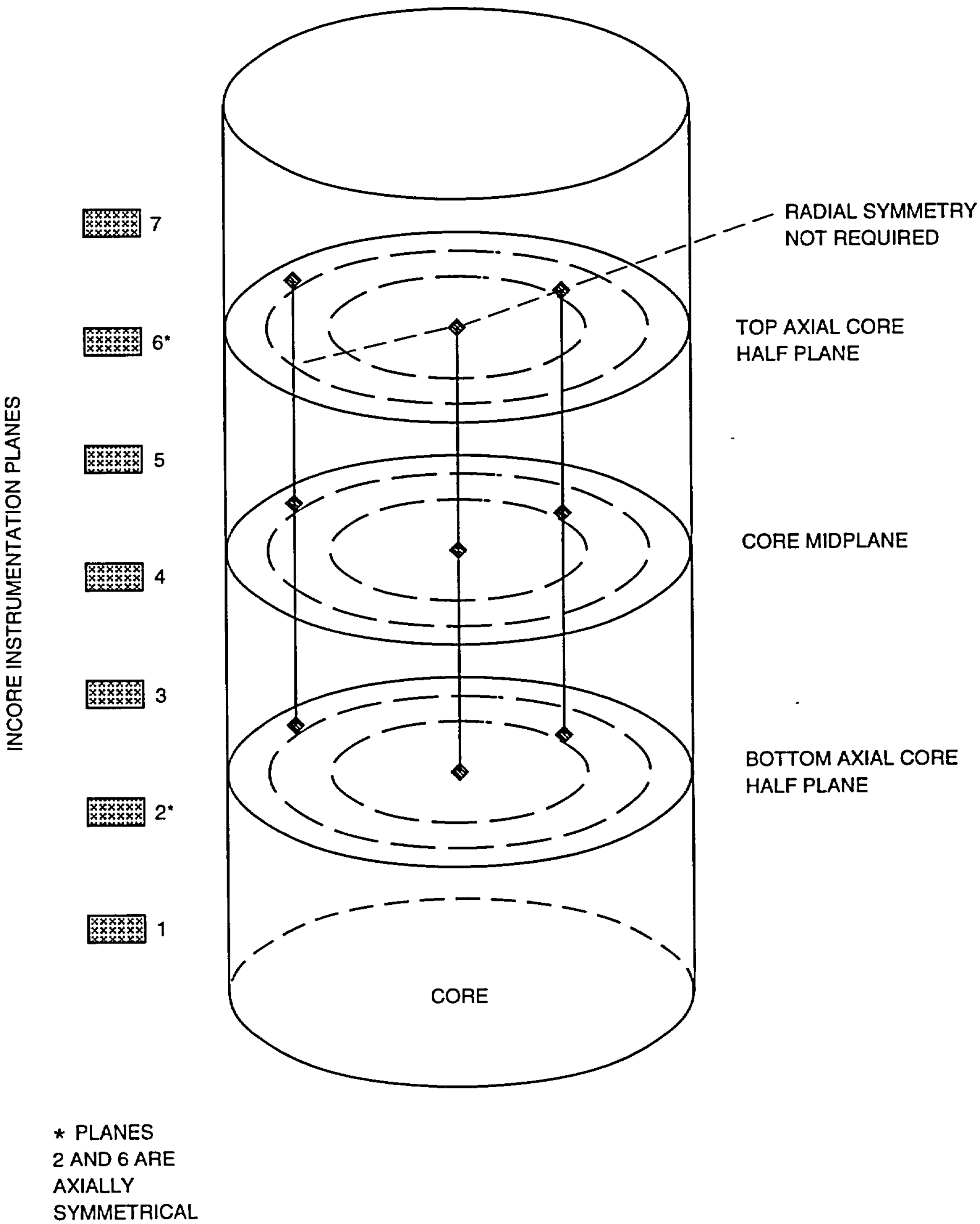

Figure 7-9 Acceptable Minimum Axial Power Imbalance Arrangement

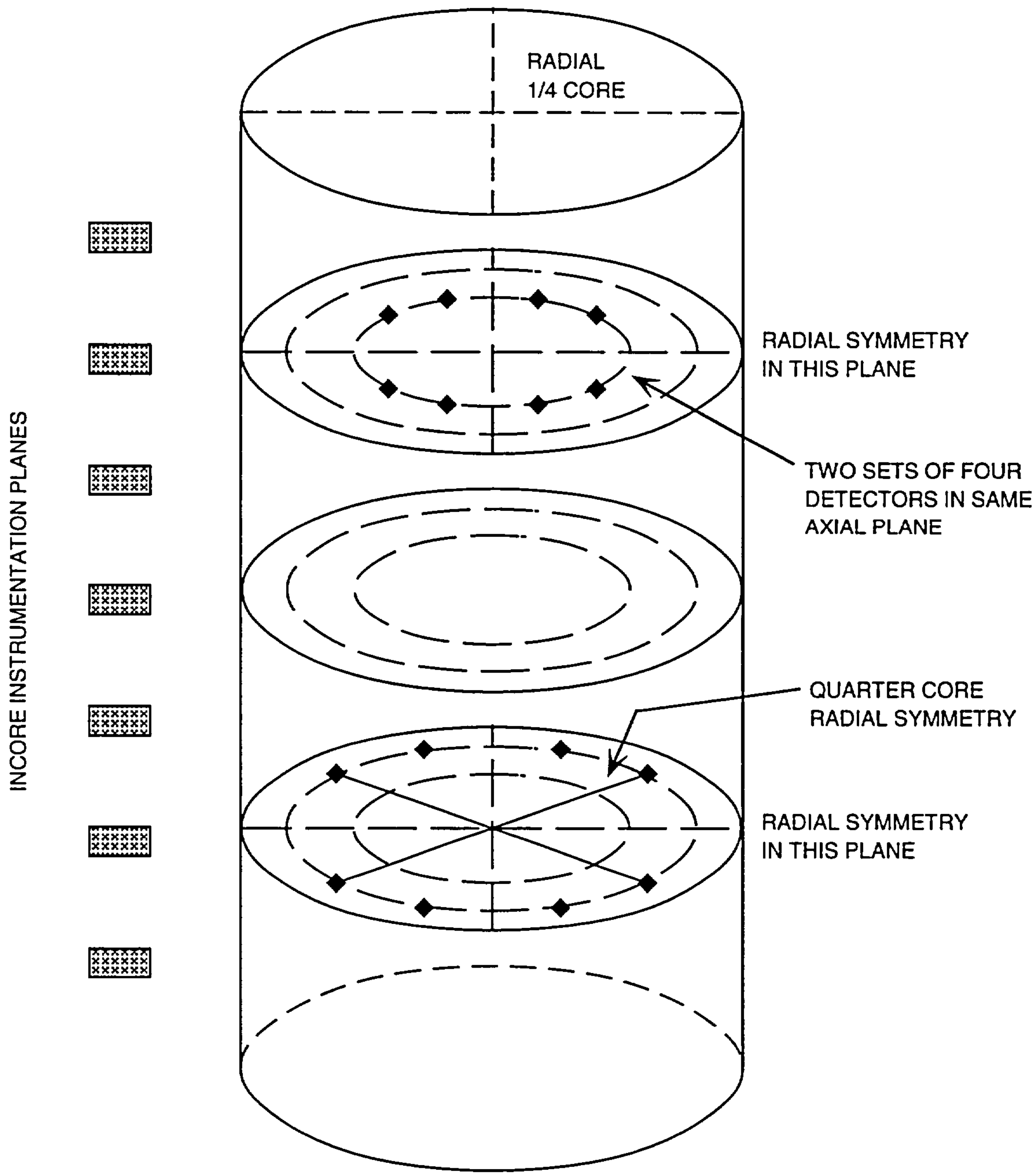

Figure 7-10 Acceptable Minimum Quadrant Power Tilt Arrangement

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CHAPTER 8

8.1 Non-Nuclear Instrumentation

8.2 Essential Controls and Instrumentation

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8.1 NON-NUCLEAR INSTRUMENTATION

Learning Objectives:

1. Explain how the following signals are developed:
   (a) Loop - T_C, T_H, ΔT, T_{ave}
   (b) Unit - T_C, T_H, ΔT, T_{ave}, ΔT_c
2. Explain how the automatic/manual selector switch determines which input signals will be used for the unit T_{ave} signal.
3. State, as listed in Table 8.1-1, the functions provided in the integrated control system by the non-nuclear instrumentation inputs.
4. Explain why temperature compensation of the RCS flow signal is required.
5. Explain why pressurizer level is density compensated.
6. List the inputs and outputs for the pressurizer level control system.
7. State the interlock provided by the pressurizer level signal and explain the purpose of the interlock.
8. List the inputs and outputs for the pressurizer pressure control system.

8.1.1 Introduction

Non-nuclear instrumentation may be defined as the sensors, instrument strings, and control system inputs that are necessary for normal plant operation.

The non-nuclear instrumentation system interfaces with the integrated control system (provides input signals), plant control systems (provides input signals), the plant computer (provides input signals), the plant annunciation system (provides alarm signals), and the essential controls and instrumentation system (receives optically isolated inputs).

A variety of signals are available from the non-nuclear instruments; they range from makeup tank pressure to reactor coolant system flow. Non-nuclear instrumentation signals are not, however, required for the safe shutdown of the plant or for the protection of the core. The system is non-Class 1E.

This chapter provides information on the more important non-nuclear instrumentation.

8.1.2 Reactor Coolant System Temperatures

The temperatures required for control of the reactor coolant system are the reactor outlet temperature (T_H), the reactor inlet temperature (T_C), the average of these two temperatures (T_{ave}), and the difference between these two temperatures (ΔT).

8.1.2.1 Reactor Outlet Temperature (T_H) Detectors

A total of six (three dual-element) resistance temperature detectors (RTDs) are installed in each reactor outlet (hot leg) (Figure 8.1-1). Two of these detectors provide temperature signals to the reactor protection system (RPS), and two detectors are installed RPS spares. One detector supplies the essential controls and instrumentation (ECI) system, and the remaining detector supplies a non-nuclear instrumentation temperature input. Each ECI RTD is wired into a resistance bridge (loop A supplies ECI-X; loop B supplies ECI-Y), which supplies a temperature input to the non-nuclear instrumentation by means of a fiber optical isolator.

8.1.2.2 T_H Signal Outputs

Either the non-nuclear instrumentation T_h signal or the essential controls and instrumentation system signal may be selected to supply either the the plant computer or the non-nuclear instrumentation circuitry with a narrow-range temperature signal (530° to 650°F) (Figure 8.1-2).

The plant computer input is supplied by the nonselected (i.e., not selected for NNI circuitry) T_H input. The plant computer uses the hot-leg temperature for the calculation of plant power output based on core ΔT, for the calculation of plant power based on the enthalpy rise across the core, and for computer-supplied temperature indication.

The non-nuclear instrumentation circuitry supplies indication, ΔT calculation, loop T_{ave} calculation, a signal to the RCS flow circuitry, and an input to the integrated control system (ICS).

T_H is supplied from each loop to the operator for indication. The indication is narrow range with a scale of 530° to 650°F.

The T_H signal that is supplied for the ΔT calculation has its associated cold-leg temperature (T_C) subtracted from it, and the result is loop ΔT. At steady-state power levels, the loop ΔT is a very accurate indication of plant power. This circuitry provides an indicator with a range of 0° to 80°F.

The T_H and T_C signals are averaged to supply an indication of loop T_{ave}. In addition to indication, loop T_{ave} may be selected as an input to the ICS.

T_H is also used to temperature compensate reactor coolant flow that is supplied from flow transmitters located in the hot-leg piping.

Each of the loop T_H signals is supplied to an averaging circuit that calculates the average hot-leg temperature for the RCS. This average T_H signal, along with each loop T_H signal, is supplied to a selector switch that, in turn, supplies an input to the ICS. The ICS uses T_H in the calculation of once-through steam generator BTU limits (see chapter 9.0). Besides the ICS input, the selected T_H signal is used for the computation of unit T_{ave} and ΔT, for the high T_H alarm set at 635°F, and for a recorder input.

8.1.2.3 Reactor Inlet Temperature (T_c) Detectors

A total of 8 RTDs are used to sense the reactor inlet temperature (T_C) in each loop (Figure 8.1-1). Two dual-element RTDs are inserted into wells in the discharge of each reactor coolant pump. Four RTDs in each coolant loop supply signals to the NNI and ECI systems. The NNI RTDs supply narrow-range circuitry (530° to 650°F) and wide-range circuitry (50° to 650°F). The ECI RTD in each loop supplies wide-range circuitry.

8.1.2.4 Wide-Range T_C Signal Outputs

The non-nuclear instrumentation wide-range T_C (50° to 650°F) RTD supplies a temperature signal to a selector switch, and the essential controls and instrumentation system T_C detector supplies the second signal to the same selector switch (Figure 8.1-3). The selector switch (one foreach loop) supplies the non-nuclear instrumentation signal to an indicator located in the main control room, to an indicator located in the auxiliary control room, and to the start circuitry for the reactor coolant pumps. Wide-range indication is necessary to allow the operator to cool down or heat up the RCS when temperature is less than that in the normal operating range (530° to 650°F). The starting of a fourth reactor coolant pump if temperature is less than 500°F is prevented by circuitry from the associated loop wide-range T_C. The nonselected wide-range temperature signal is sent to the computer for indication.

8.1.2.5 Narrow-Range T_C Signal Outputs

The narrow-range T_C signals are supplied to the plant computer, to indication circuits, and to the ICS (Figure 8.1-4). The plant computer inputs are supplied from each NNI narrow-range T_c RTD. These inputs are used in the calculation of the departure from nucleate boiling ratio (DNBR), the calculation of plant power based on the enthalpy rise across the core, and the calculation of plant power based on core ΔT.

The loop indication circuitry receives inputs from both T_C narrow-range signals in that loop and the average of these two inputs. A selector switch position decides which signal will be used to provide indication of T_C. A selector switch is provided for each loop.

The selected signal provides the operator with narrow-range temperature indication (530° to 650°F), provides an input to loop ΔT and loop T_{ave}, and provides inputs to the unit T_C circuitry and to a difference unit that provides a ΔT_C signal to the ICS.

The T_C input to the loop ΔT circuitry is subtracted from loop T_H and provides the operator with ΔT indication with a range of 0° to 80°F.

The T_C input to the loop T_{ave} computation is averaged with loop T_H to provide loop T_{ave}. Loop T_{ave} has a range of 530° to 650°F and may be used as an input to the ICS.

The unit T_C signal is derived from the average of the selected T_C signals of both loops. Unit T_C is averaged with unit T_H to yield unit T_{ave}. Unit T_{ave} may be used as an input to the ICS.

A ΔT_C input is supplied to the feedwater demand subassembly for proportioning of feedwater flows if a difference in loop T_C exists (see chapter 9.0).

8.1.2.6 Differential Temperature (ΔT) Signals

Reactor coolant differential temperature (ΔT) is calculated from the T_H and T_C outputs and is used only for indication. Three different ΔT signals, with a range of 0 to 80°F, are displayed; that is, one from each loop and unit ΔT (Figure 8.1-5).

The unit ΔT is calculated by subtracting unit T_C from unit T_H. Unit ΔT is displayed in the main control room.

8.1.2.7 Average Reactor Coolant System Temperature (T_{ave})

The calculated average reactor coolant system (RCS) temperature (T_{ave}) is used for indication and control (Figure 8.1-5).

Three T_{ave} signals are computed: loop A T_{ave}, loop B T_{ave}, and unit T_{ave}. The loop T_{ave} signal is the average of the selected loop T_H and loop T_C signals, and the unit T_{ave} is the average of unit T_H and unit T_C.

The three T_{ave} signals are supplied to an automatic/manual selector switch, which also receives inputs from loop A and loop B RCS flow. As long as all four reactor coolant pumps are running, the operator may select any of the three signals for use in the reactor demand subassembly of the ICS. However, during asymmetric loop flow conditions, the automatic/manual selector switch automatically supplies the ICS with the loop T_{ave} signal from the loop with the highest RCS flow. This selection is performed through interlock circuitry from RCS flow, and the operator cannot override this selection. The output of the automatic/manual selector switch is digitally displayed in the control room.

8.1.3 Reactor Coolant System Flow

8.1.3.1 Reactor Coolant System Flow Detection

Reactor coolant flow is sensed by a flow element located in each reactor coolant hot leg (Figure 8.1-6). The flow element is a flow tube designed to provide minimum restriction to RCS flow. The flow tube, pictured in Figure 8.1-7, is an integral portion of the hot-leg piping. The tube contains penetrations that provide a method of sensing differential pressure; that is, a high-pressure tap that senses the velocity head of the RCS fluid, and a low-pressure tap that senses the static head of the RCS. The flow tube taps are piped to six flow transmitters for each loop. Four of these flow transmitters supply flow signals to the reactor protection system (RPS), and two of these transmitters supply the non-nuclear instrumentation system.

8.1.3.2 Reactor Coolant Flow Signal Outputs

The outputs of each loop's non-nuclear instrumentation flow transmitters are supplied to a selector switch that decides which flow transmitter supplies the indication and control signal (Figure 8.1-8). The nonselected signal is supplied to the plant computer.

The selected flow signal is routed to a square root extractor that converts the differential pressure signal to a flow signal (flow is proportional to the square root of the ΔP). From the square root extractor, the flow signal is supplied to a function generator. In the function generator, the flow signal is density compensated by the associated loop T_H signal. The output of the function generator is supplied to an indicator, a bistable, the ICS, and a summing amplifier (Σ). An indication of loop flow with a range of 0 to 120 × 10^6 lb mass per hour is provided for each loop.

The bistable performs two functions: it supplies a low flow alarm, and it supplies an input to the T_{ave} automatic/manual selector switch. The low flow alarm is set at approximately 90% of rated flow and alerts the operator to a degraded flow condition. The input to the T_{ave} automatic/manual selector switch causes the selection of the opposite loop T_{ave} when loop flow drops to approximately 90%.

Individual loop flow signals are supplied to the feedwater demand subassembly of the ICS and are used for the control of feedwater to the once-through steam generators (OTSGs). The ratio of feedwater supplied to the steam generators depends on the RCS loop flows through the primary (tube) sides of the OTSGs.

The summing amplifier sums the flow signals from the individual loops and provides inputs to a recorder and to the ICS. The recorder provides the operator with an indication of total core flow, which has a range of 0 to 240 × 10^6 lbm/hr. The unit load demand of the ICS receives an input of total RCS flow and, on the basis of this input, will run back unit electrical load to maintain power production consistent with RCS flow.

As previously mentioned, the plant computer receives inputs from the nonselected flow transmitters. The RCS flow inputs are used in the calculation of DNBR and core thermal power and in the primary heat balance program.

8.1.4 Pressurizer Level (Figure 8.1-9)

The pressurizer is equipped with two level transmitters with a 0 to 400-in. range. These transmitters supply the essential controls and instrumentation system with redundant inputs. The ECI level transmitter signals are fed to the non-nuclear instrumentation system by means of fiber optical isolators. From the optical isolators, the level transmitter signals are routed to a selector switch. The selector switch is used to select the signal that is to be used for pressurizer level control. The nonselected pressurizer level signal is supplied to the plant computer for indication and annunciation.

The selected pressurizer level input is temperature compensated by the pressurizer water space temperature. Temperature compensation is necessary to provide accurate level indication for temperatures ranging from cold shutdown pressurizer temperatures to normal operating pressurizer temperatures. The temperature input to the pressurizer level circuitry also supplies an indicator with a 0 to 700°F range. The output of the temperature compensation circuitry is selected compensated pressurizer level.

The pressurizer level circuitry supplies low, low-low, high, and high-high alarm bistables. The low- and high-level alarm setpoints are based on the pressurizer level change associated with a 5°F change in T_{ave}. The high-high alarm alerts the operator that the pressurizer is approaching solid water conditions. The alarm associated with the low-low bistable informs the operator of an extremely low-level condition. The low-low alarm also is used to de-energize the pressurizer heaters. This interlock prevents any heater damage that might occur if the heaters were to become uncovered while in operation.

In addition to providing alarms, the selected compensated pressurizer level is used for pressurizer level control. The control scheme consists of comparing the actual pressurizer level with an operator-supplied setpoint. The setpoint is manually varied as a function of T_{ave}. As shown in Figure 8.1-10, the no-load pressurizer level, corresponding to a T_{ave} of 550°F, is 180 in. As power is escalated, T_{ave} increases, and the operator changes the pressurizer level setpoint. The change in setpoint allows part of the volume increase associated with the change in T_{ave} to be accomodated by the increase in pressurizer level. The remaining volume change is accommodated by diverting letdown flow to the reactor coolant bleed tanks. The above actions are continued until T_{ave} reaches 601°F (15% power value); T_{ave} is then held constant, and the pressurizer level setpoint is maintained at 220 in.

Regardless of the value of the level setpoint, it is compared with actual pressurizer level in a difference (Δ) amplifier. The output of this amplifier, pressurizer level error, is supplied to a proportional-plus-integral controller that modifies the error signal on the basis of the amount and duration of the deviation from setpoint. From the proportional-integral controller, the signal is routed through a manual/automatic station and is then supplied to an electrical-to-pneumatic (E/P) converter that changes the error signal to an air signal. The air signal is used to modulate the makeup control valve (V-46). The modulation of makeup rate, along with a constant letdown rate, allows the control of pressurizer level. The manual/automatic station allows the operator to control the position of the makeup control valve when manual is selected.

8.1.5 Pressurizer Pressure

8.1.5.1 Wide-Range Pressurizer Pressure

Two wide-range (0 to 2500-psig) pressurizer pressure inputs are supplied from the essential controls and instrumentation system to the nonnuclear instrumentation system (Figure 8.1-11). The signals are routed through optical isolators to a selector switch that selects the wide-range pressure that is to be used by the non-nuclear instrumentation system. The nonselected signal is supplied to the plant computer. Wide-range pressure is used to monitor RCS pressure/temperature limits during plant heatups and cooldowns.

8.1.5.2 Narrow-Range Pressurizer Pressure

Two narrow-range pressurizer pressure transmitters send signals to the non-nuclear instrumentation system (Figure 8.1-12). A selector switch provides a method of selecting the signal that is to be used for pressurizer pressure control. As is typical in the non-nuclear instrumentation system, the nonselected signal is supplied to the plant computer and is used for indication and DNBR calculations.

The selected pressurizer pressure transmitter is used to provide alarms; to control the power-operated relief valve, the spray valve, the on/off pressurizer heaters, and the proportional pressurizer heaters; and to provide a recorder with an indication range of 1500 to 2500 psig.

The high- and low-pressure alarms are driven by bistables that receive an input directly from the selected pressure transmitter. These alarms are used to alert the operator that RCS pressure has deviated from the normal control band.

The power-operated relief valve (PORV) is also controlled by a bistable that receives an input directly from the selected pressure transmitter. The bistable opens the PORV at 2400 psig and closes the PORV when pressure drops to 2375 psig. The bistable control of the PORV is independent of the controller/setpoint comparison that is used for heater and spray valve control.

The remaining pressurizer pressure control devices are controlled by the output of a summing amplifier (Σ). The summing amplifier has two inputs: actual pressurizer pressure and the setpoint. The setpoint is supplied by a setpoint module in the non-nuclear instrumentation cabinets and is normally adjusted to a value of 2195 psig. However, provisions are installed to allow a different value to be used. The resultant error from the comparison of actual pressurizer pressure to the setpoint is used to control the spray valve and the pressurizer heaters.

The control of the spray valve is accomplished by a bistable that opens the valve when pressure increases to 2245 psig and closes the valve when pressure decreases to 2195 psig.

The control of pressurizer heater banks 2, 3, and 4 is also accomplished by bistables. The deviation of pressurizer pressure from setpoint is sensed by these bistables, and the pressurizer heater banks are sequentially energized as pressure decreases. Bank 2 is energized when pressure drops to 2175 psig, bank 3 is energized when pressure drops to 2160 psig, and bank 4 is energized when pressure decreases to 2145 psig. As pressure increases, the heaters are also sequentially de-energized with setpoints of 2160, 2180, and 2195 psig for banks 4, 3, and 2, respectively. The pressurizer heaters are interlocked with pressurizer level. Should pressurizer level drop to the low-low setpoint, automatic heater energization is prevented until the level returns to a value above the low-low setpoint.

The control of the proportional heaters is accomplished by a proportional-integral controller through a pressurizer level bistable. As pressure deviates from setpoint, the controller signal causes a silicon controlled rectifier (SCR) to increase the power output to the proportional heaters. The proportional heaters are in a maximum power condition when pressure drops to 2175 psig and a minimum power condition at a pressure of 2195 psig. A manual/automatic station is installed to allow operator control of the proportional heaters. Pressurizer level is also used as an interlock in the proportional heater control circuitry. If pressurizer level drops to the low-low setpoint, the output of the SCR control is driven to its minimum value.

8.1.6 Feedwater System Instrumentation

The sensing of feedwater flow, feedwater valve differential pressure, and feedwater temperature is performed to provide the ICS with the required inputs. Two feedwater flow signals (Figure 8.1-13) are processed by the non-nuclear instrumentation system: (1) a low-range flow signal, called startup feedwater flow, with a range of 0 to 2×10^6 lbm/hr, and (2) a full-range signal, called main feedwater flow, with a range of 0 to 9×10^6 lbm/hr. Startup feedwater flow is sensed from a venturi located in series with the startup feedwater regulating valve, and main feedwater flow is sensed by a venturi located in series with both the main and startup feedwater regulating valves. Both flow signals are density compensated by feedwater temperature and are used as inputs to the ICS.

The pressure differential between the inlet and the outlet of each feedwater regulating valve is measured by differential pressure transmitters. The output of the differential pressure transmitters is supplied to the ICS, which regulates feedwater pump turbine speed on the basis of the transmitter signal.

Feedwater temperature is used to density compensate the feedwater flow signals and as an input to the ICS. Feedwater temperature is measured by dual-element resistance temperature detectors located downstream of the main feedwater isolation valves (MFIVs).

8.1.6.1 Feedwater Flow

Figure 8.1-14 shows the feedwater instrumentation for feedwater loop A. The instrumentation for loop B is identical; therefore, the following description is applicable to both loops.

A single flow transmitter is used to sense startup feedwater flow. The output of this transmitter is sent to a square root extractor (for conversion into a flow signal) and to the plant computer, where an internal conversion is used to calculate startup feedwater flow.

From the output of the square root extractor, the flow signal is sent to a variable gain unit (χ). The variable gain unit increases or decreases the flow signal as a function of feedwater temperature. The feedwater temperature signal is supplied through a function generator (f(T)) from the selected feedwater temperature, and the variable gain unit is used to provide the necessary temperature compensation of feedwater flow.

The temperature-compensated, startup feedwater flow signal supplies an indicator with a range of 0 to 2×10^6 lbm/hr and an input to the ICS. Startup feedwater flow is used by the ICS when the main feedwater block valve is closed. The main feedwater block valve automatically opens when the startup regulating valve reaches an 80% open position. When the main block valve is fully open, the ICS uses main feedwater flow as an input.

Main feedwater flow is sensed by two flow transmitters that supply inputs to square root extractors and a selector switch. The square root extractors convert the ΔP signals into flow signals, and the selector switch chooses the plant computer input from one of the two transmitters. The conversion of the raw ΔP signal into flow is performed by the computer software.

The outputs of the square root extractors are supplied to variable gain units that also receive inputs from feedwater temperature function generators. These function generators density compensate the main feedwater flow signals by changing the gains of the variable gain units.

From the variable gain units, the density-compensated main feedwater flow signals are routed to a selector switch. The signal that is selected by the selector switch supplies indication and the ICS; the nonselected signal is supplied to the plant computer for indication and secondary power calculations. The selected signal provides an indicator (with a range of 0 to 9×10^6 lbm/hr) and an ICS input that is used for comparison with feedwater demand. The selected loop feedwater flow signals are summed by the ICS and compared to feedwater demand for the generation of cross limits (see Chapter 9.0).

8.1.6.2 Feedwater Valve Differential Pressure

Feedwater valve differential pressure (ΔP) is measured by two differential pressure transmitters for each feedwater loop (Figure 8.1-14). The outputs of the transmitters are supplied to a selector switch. The selected transmitter supplies an indicator (with a range of 0 to 100 psid) and the ICS. The ICS uses feedwater valve ΔP to control main feedwater pump speed. The nonselected transmitter output is supplied to the plant computer for indication purposes.

8.1.6.3 Feedwater Temperature

A dual-element resistance temperature detector is installed in a temperature well downstream of the main feedwater isolation valves (MFIVs) in each feedwater loop (Figure 8.1-15). Each element supplies a bridge circuit that converts the resistance to a temperature signal. Each bridge circuit, in turn, feeds a function generator (f(T)), which is used to density compensate one of the two main feedwater flow signals, and a selector switch.

The selected feedwater temperature supplies density compensation for startup feedwater flow and an indicator with a range of 0 to 600°F, and the selected loop temperatures from both loops are averaged by the ICS. The average feedwater temperature is used by the ICS to limit feedwater demand. The nonselected signal is supplied to the plant computer for indication and for the calculation of secondary plant power.

8.1.7 Steam System Instrumentation

The sensing of startup-range OTSG level, turbine header (steam) pressure, and OTSG pressure provides the ICS with the parameters required to control the plant.

8.1.7.1 Once-Through Steam Generator Level Instrumentation

Two different ranges of OTSG level transmitters are installed on the integral economizer OTSGs: (1) startup-range transmitters that provide indication and control signals and (2) full-range transmitters that are used for indication (Figure 8.1-15).

The startup-range circuitry consists of two redundant ECI level transmitters for each OTSG, which supply outputs through optical isolators to a selector switch. The selected startup-range level, in turn, is supplied to an alarm bistable that alerts the operator to high- and low-level conditions in the OTSG and to the ICS, which uses the level information for low-level limit control of the OTSGs. The nonselected signal is supplied to the plant computer for indication functions. Each of the startup-range detectors supplies an indicator with a range of 0 to 80 in.

The single full-range level signal (0 to 100%) for each OTSG supplies level information to the operators when full wet layup conditions are established during cold shutdown.

8.1.7.2 Turbine Header and OTSG Pressure Instrumentation

The turbine header pressure is supplied to the non-nuclear instrumentation system by a pressure transmitter located on the steam header from each steam generator (Figure 8.1-15). The pressure transmitter outputs are supplied to a selector switch. The selected pressure transmitter signal supplies a recorder with a range of 500 to 1500 psig, high- and low-pressure alarms, and an input to the ICS that is used for turbine load control and steam dump valve control. The nonselected pressure transmitter signal is supplied to the plant computer for display. OTSG steam pressure (two detectors per OTSG) is supplied to the ICS for the calculation of BTU limits.

8.1.8 Smart Analog Signal Select System

Several significant plant transients have been caused by the failure of the NNI input signals to the ICS. These transients range from uncomplicated reactor trips to severe overcooling events. The causes of input signal failures have ranged from simple transmitter failures to losses of power to the NNI system.

Ideally, one half of the NNI transmitters are powered from one power supply (this is sometimes called NNI-X), and the redundant transmitters are powered from a separate power supply (referred to as NNI-Y). In the event of a loss of power, half of the instrumentation would be available to control the plant in a stable post-trip condition.

The Smart Analog Signal Select (SASS) System is designed to mitigate some of the problems associated with ICS input signal failures. The SASS System has been installed at all operating B&W plants.

SASS is a computer-based signal selection device that is designed to sense degradation of redundant input signals and to automatically transfer to an operable input if a signal failure is detected. The computer receives inputs from redundant signal transmitters (Figure 8.1-16). The signals are compared in magnitude to determine if a 3 percent mismatch exists. If a mismatch of this magnitude is present, the program determines the rate of change of the mismatched signal by comparing the signal with its previous value. If a large rate of change occurs (> 30%/second), the program reiterates to verify failure. If a signal failure is also determined by the second program execution, then SASS will select the operable transmitter for ICS input and control board indication. An alarm will also be generated. If the program determines that only a signal mismatch exists, control room annunciators are actuated, and the system shifts to manual. The operator must manually select the operable transmitter.

8.1.9 Summary

The non-nuclear instrumentation system processes many primary and secondary plant parameter signals for use in the plant control systems. Reactor coolant system temperatures are combined in various ways to develop both loop and unit temperature signals. Figure 8.1-17 shows a simplified one-line diagram of how these signals are developed. The integrated control system uses many of these plant parameters. Table 8.1-1 lists those parameters which input to the ICS and the functions that they provide.

TABLE 8.1-1 NON-NUCLEAR INSTRUMENTATION INPUTS TO INTEGRATED CONTROL SYSTEM

NNI Signal	ICS Subassembly	Function
Unit T_h	Feedwater Demand	Calculation of BTU Limits
Delta T_c	Feedwater Demand	Calculation of feedwater flow ratio for OTSGs
Unit T_{ave}	Reactor Demand	Modify reactor demand signal for regulating rod movement
Loop A RCS Flow	Feedwater Demand	Calculation of BTU limits and feedwater flow rationing
Loop B RCS Flow	Feedwater Demand	Calculation of BTU limits and feedwater flow rationing
Total RCS Flow	Unit Load Demand	Initiation of runback signals
Main Feedwater Flow	Feedwater Demand	Compared to feedwater demand to develop error signal
Startup Feedwater Flow	Feedwater Demand	Control position of startup regu-lating valve
Main Feedwater Temperature	Feedwater Demand	Calculation of BTU limits
Main Feedwater Valve ΔP	Feedwater Demand	Control main feedwater pump speed
OTSG Startup Level	Feedwater Demand	Low-level limit control
Turbine Header Pressure	Integrated Master	Turbine load control and steam dump valve control
OTSG Pressure	Feedwater Demand	Calculation of BTU limits

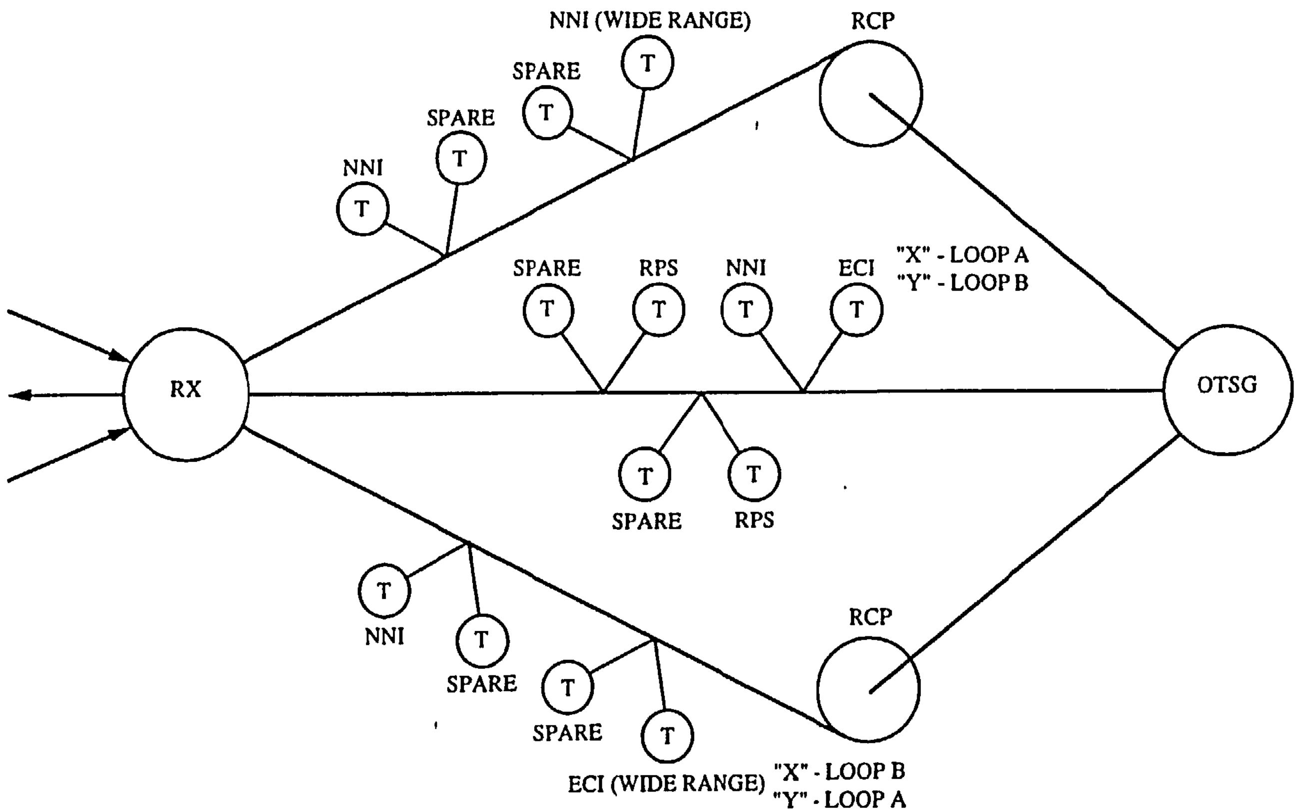

Figure 8.1-1 Reactor Coolant System Temperature Detector Locations

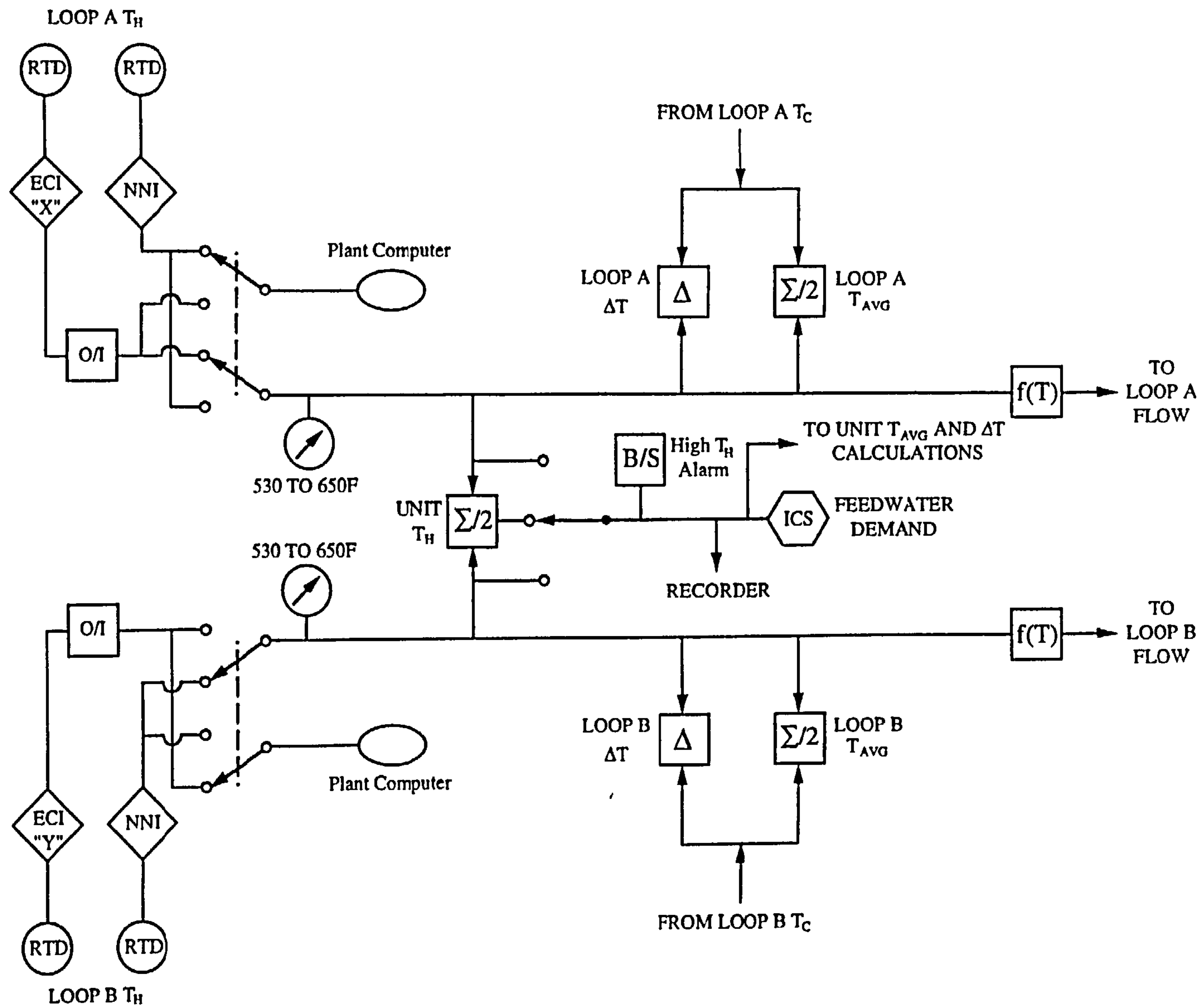

Figure 8.1-2 Reactor Outlet Temperature (T_h)

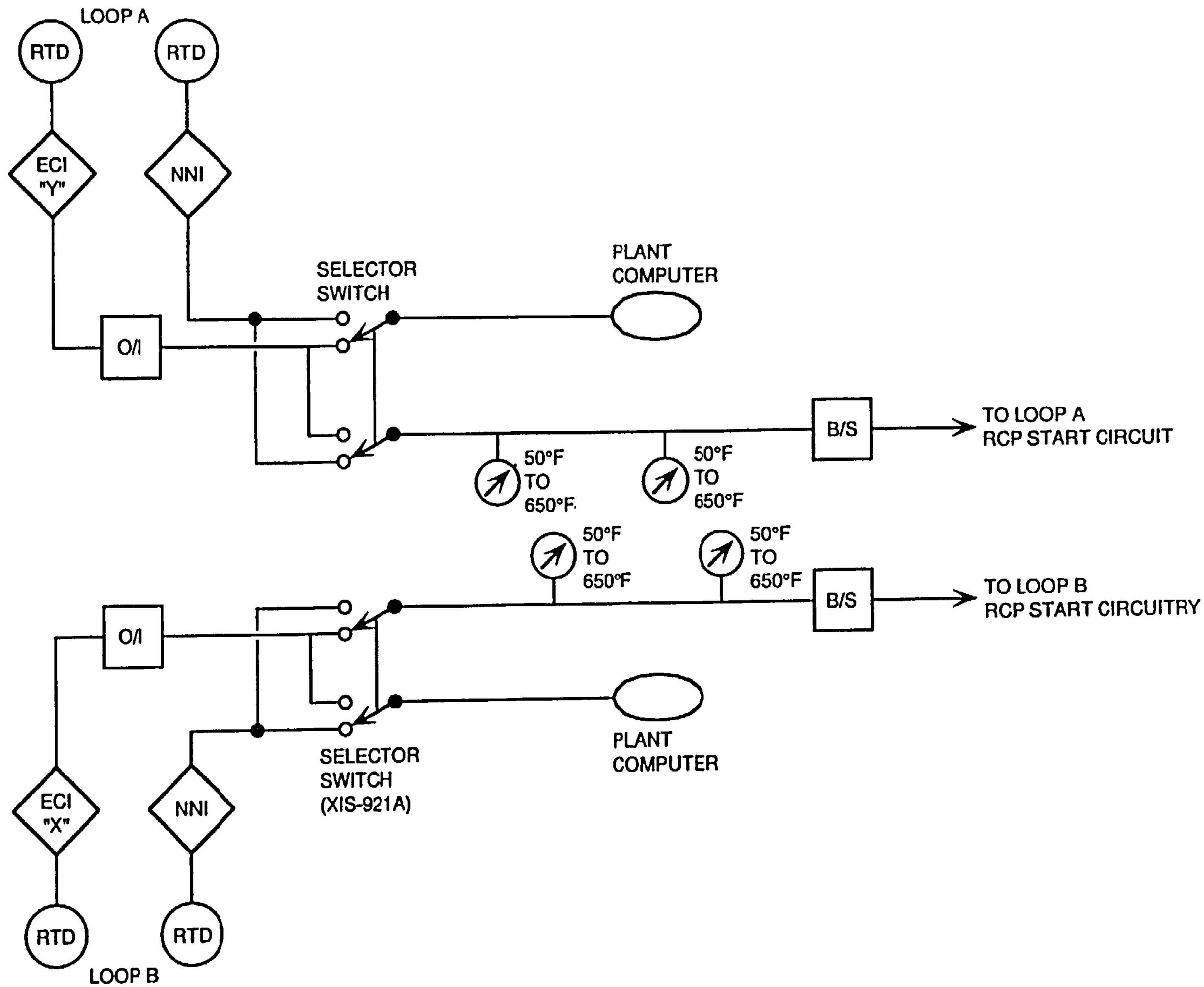

Figure 8.1-3 Wide-Range Reactor Coolant Inlet Temperature (Tc)

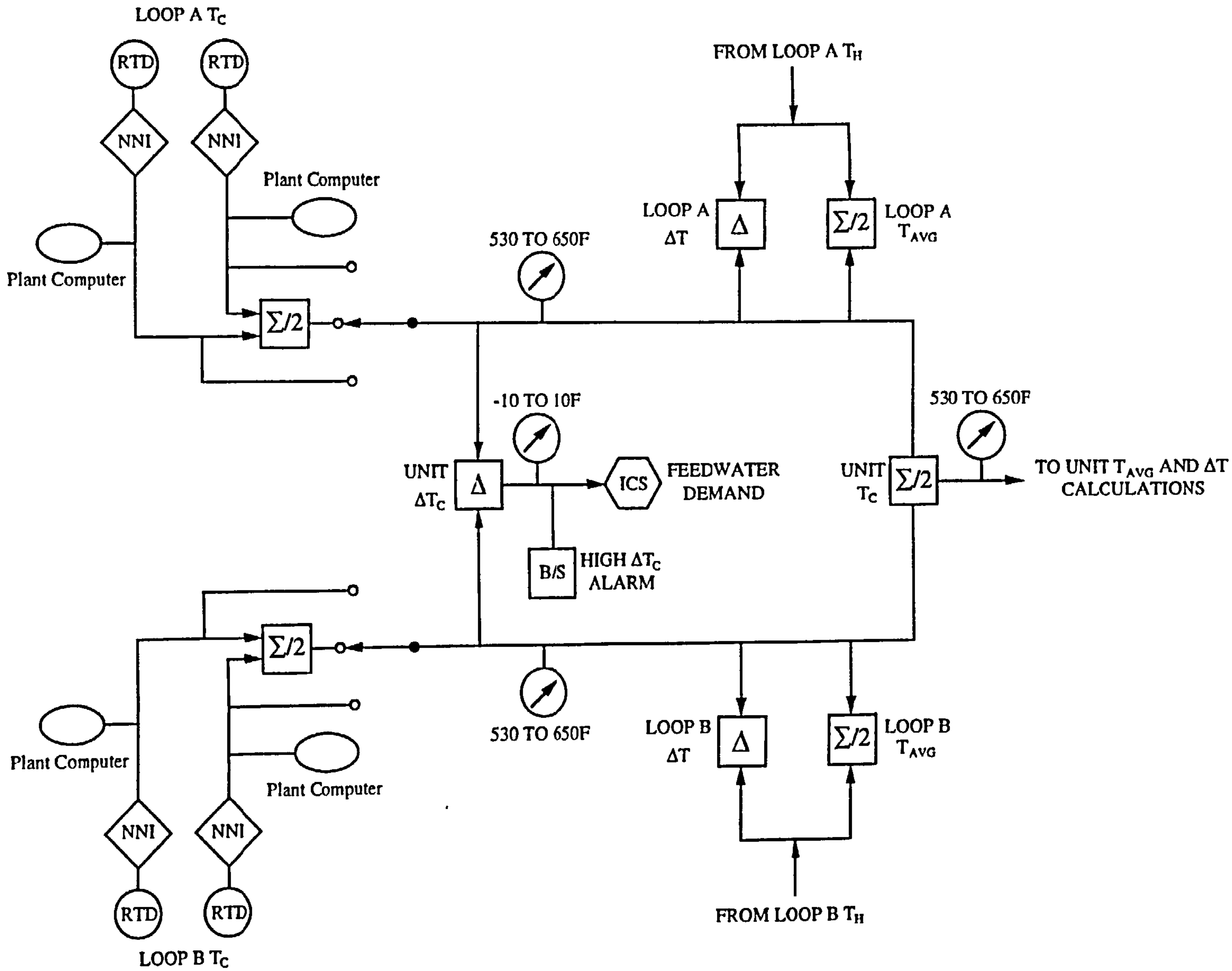

Figure 8.1-4 Narrow Range Reactor Coolant Inlet Temperature (T_C)

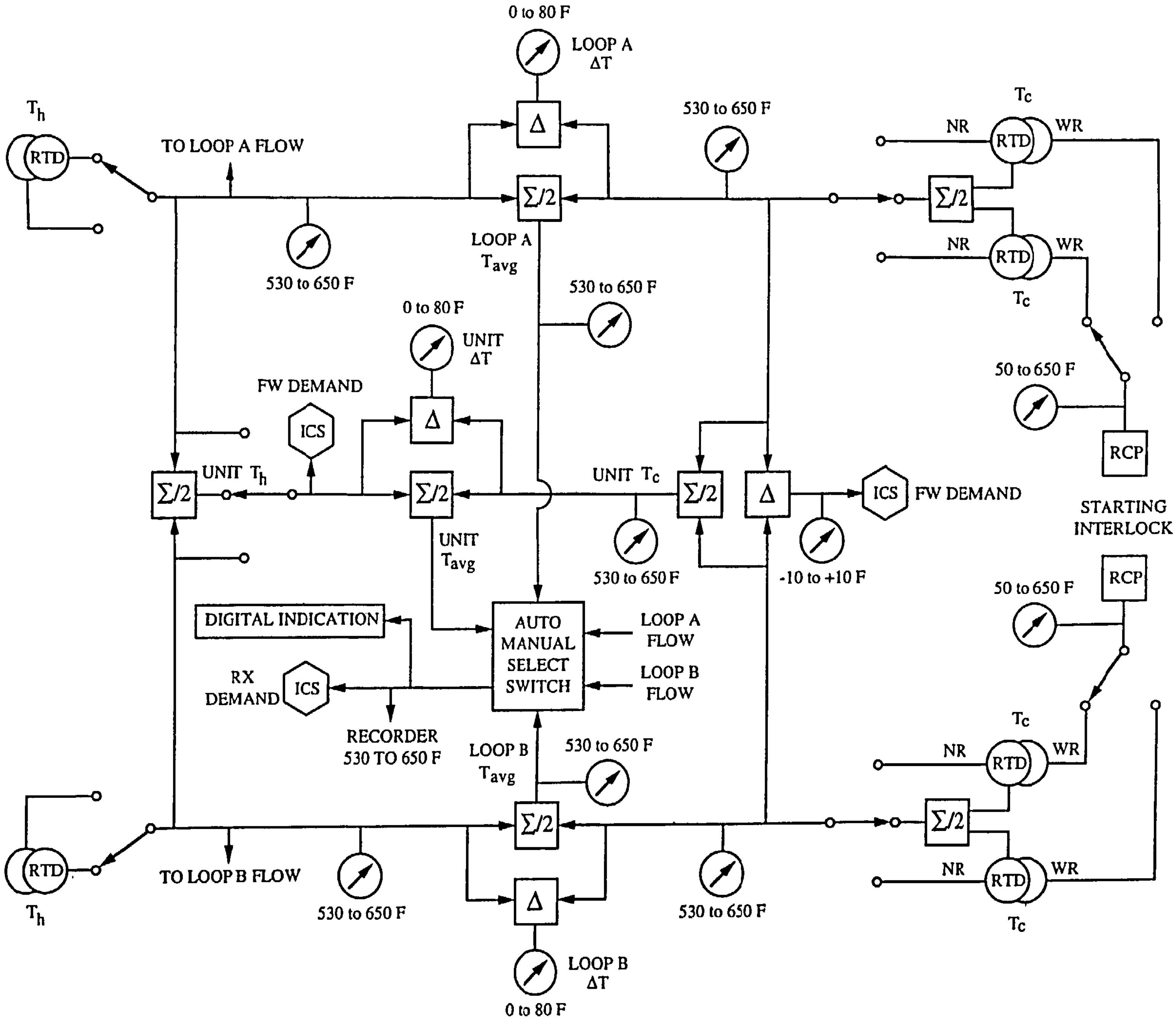

Figure 8.1-5 Non-Nuclear Instrumentation Reactor Coolant System Temperature

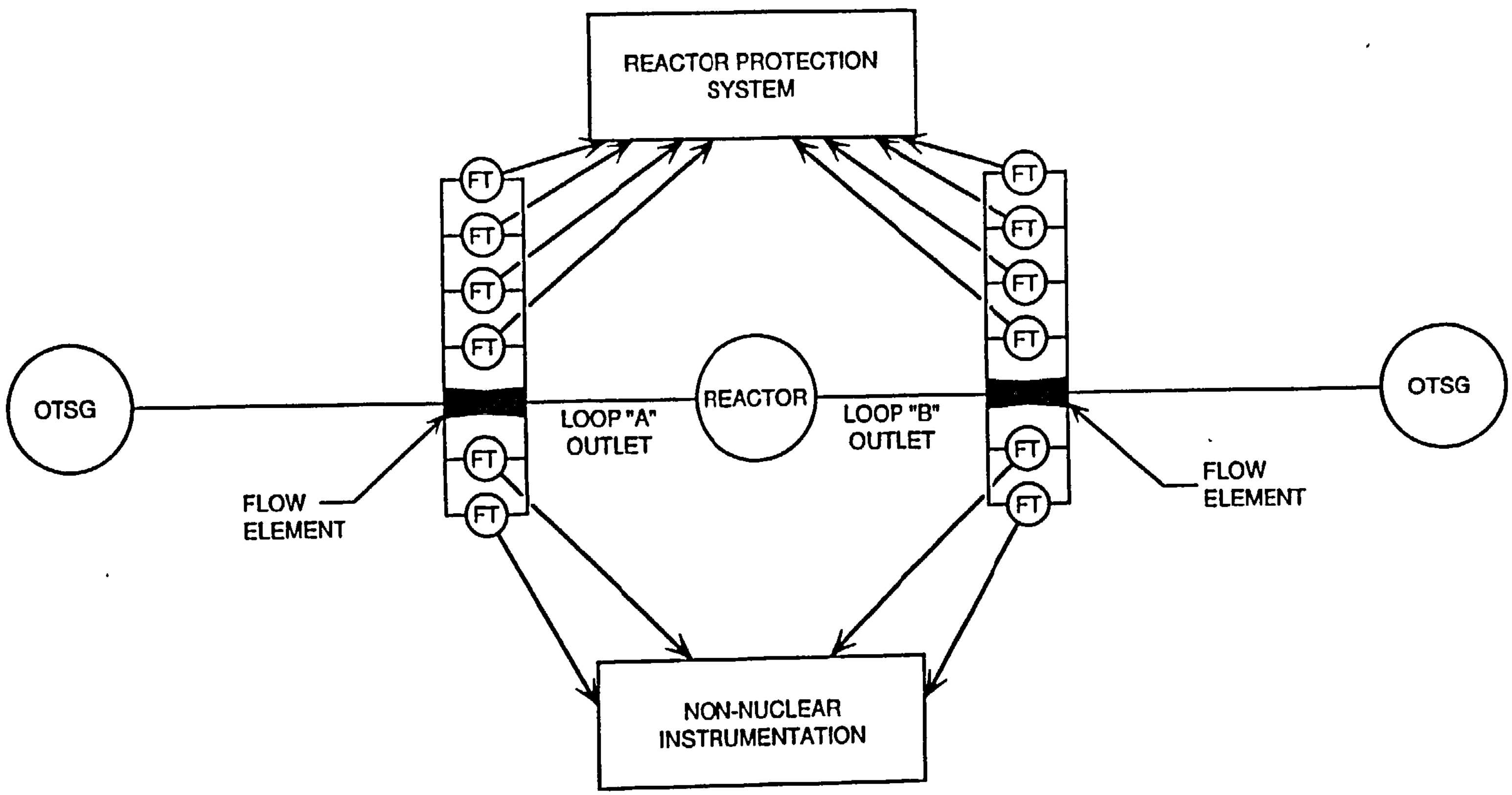

Figure 8.1-6 Reactor Coolant System Flow Detector Locations

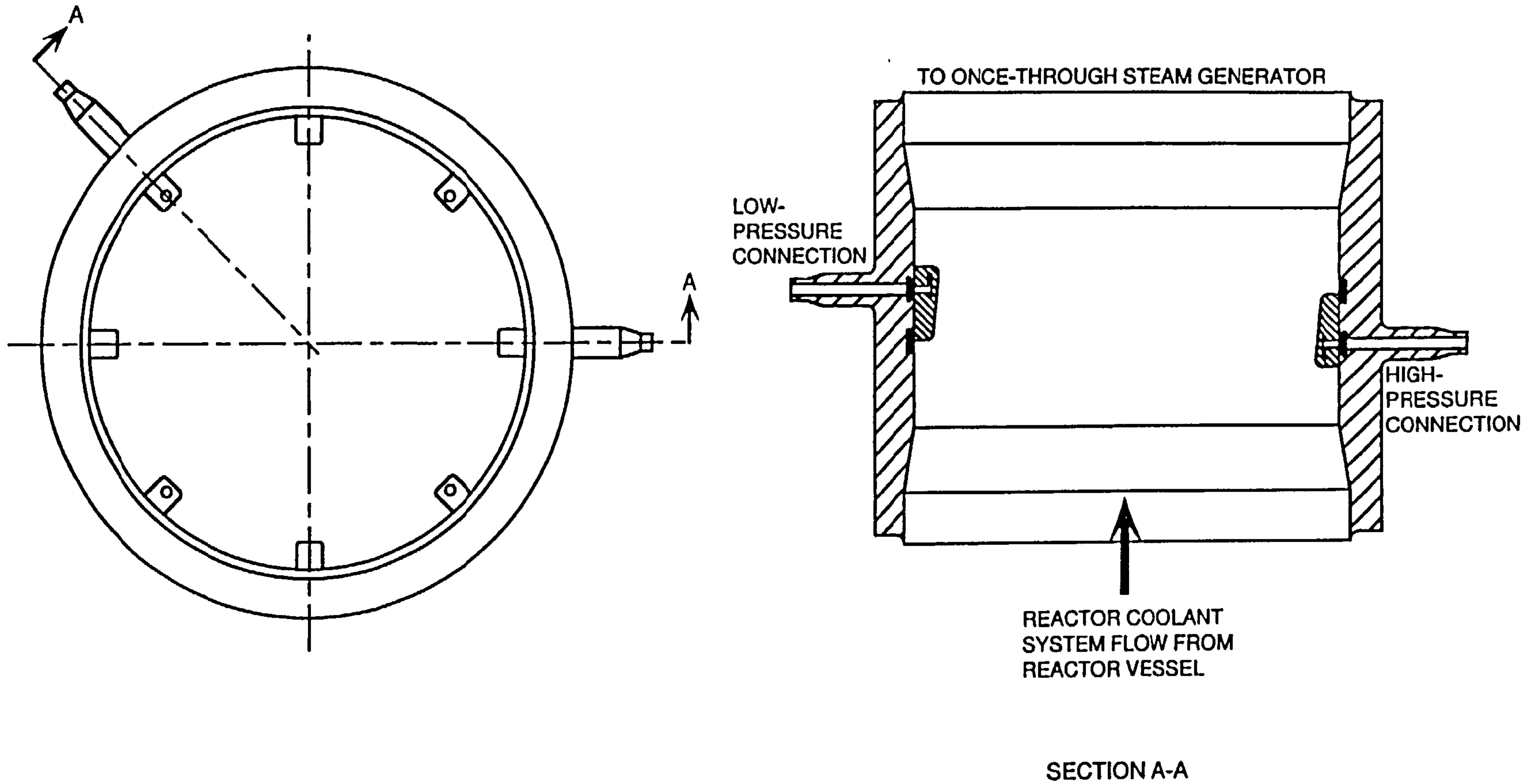

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Figure 8.1-7 Reactor Coolant Flow Tube

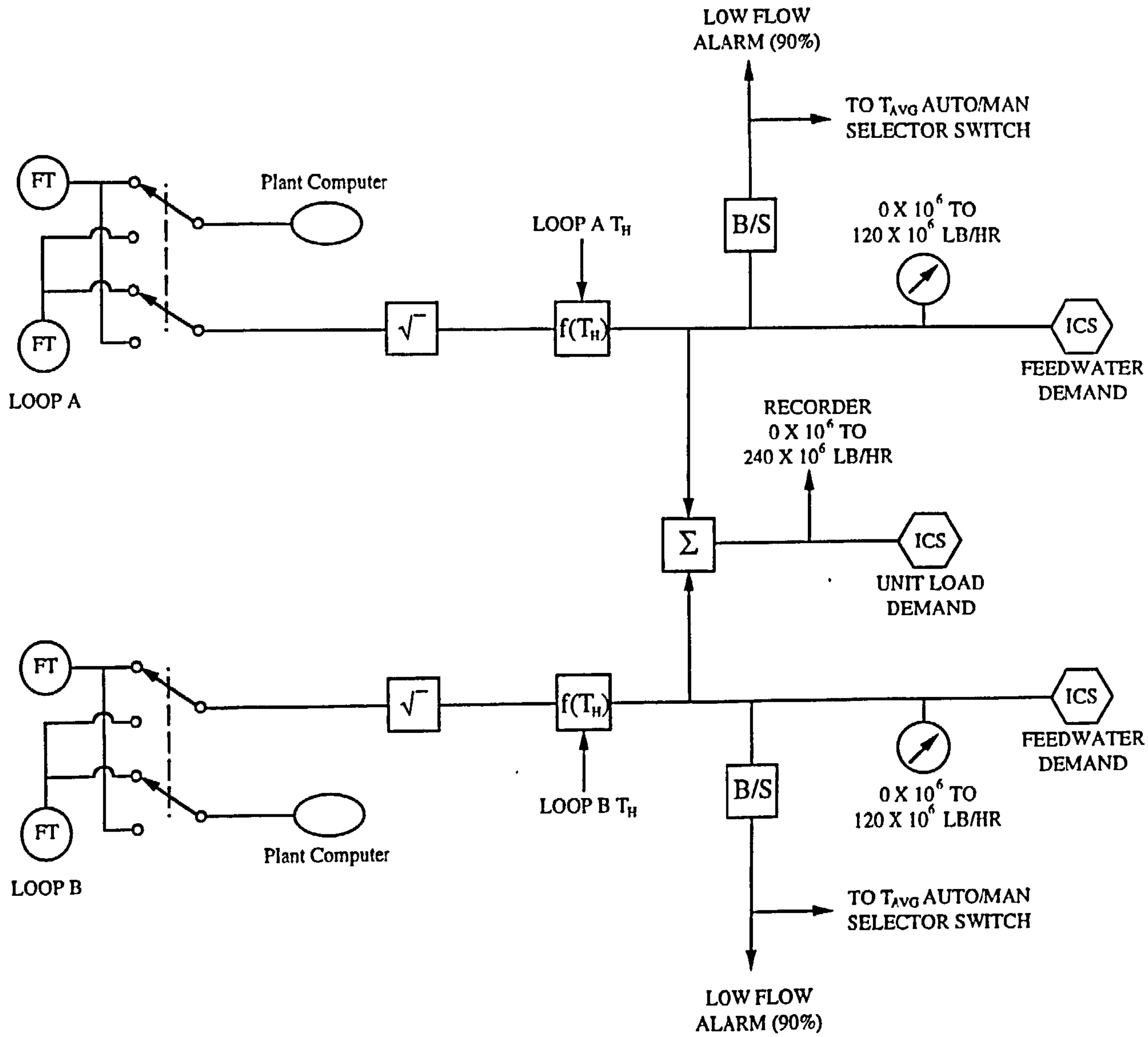

Figure 8.1-8 Non-Nuclear Instrumentation Reactor Coolant Flow

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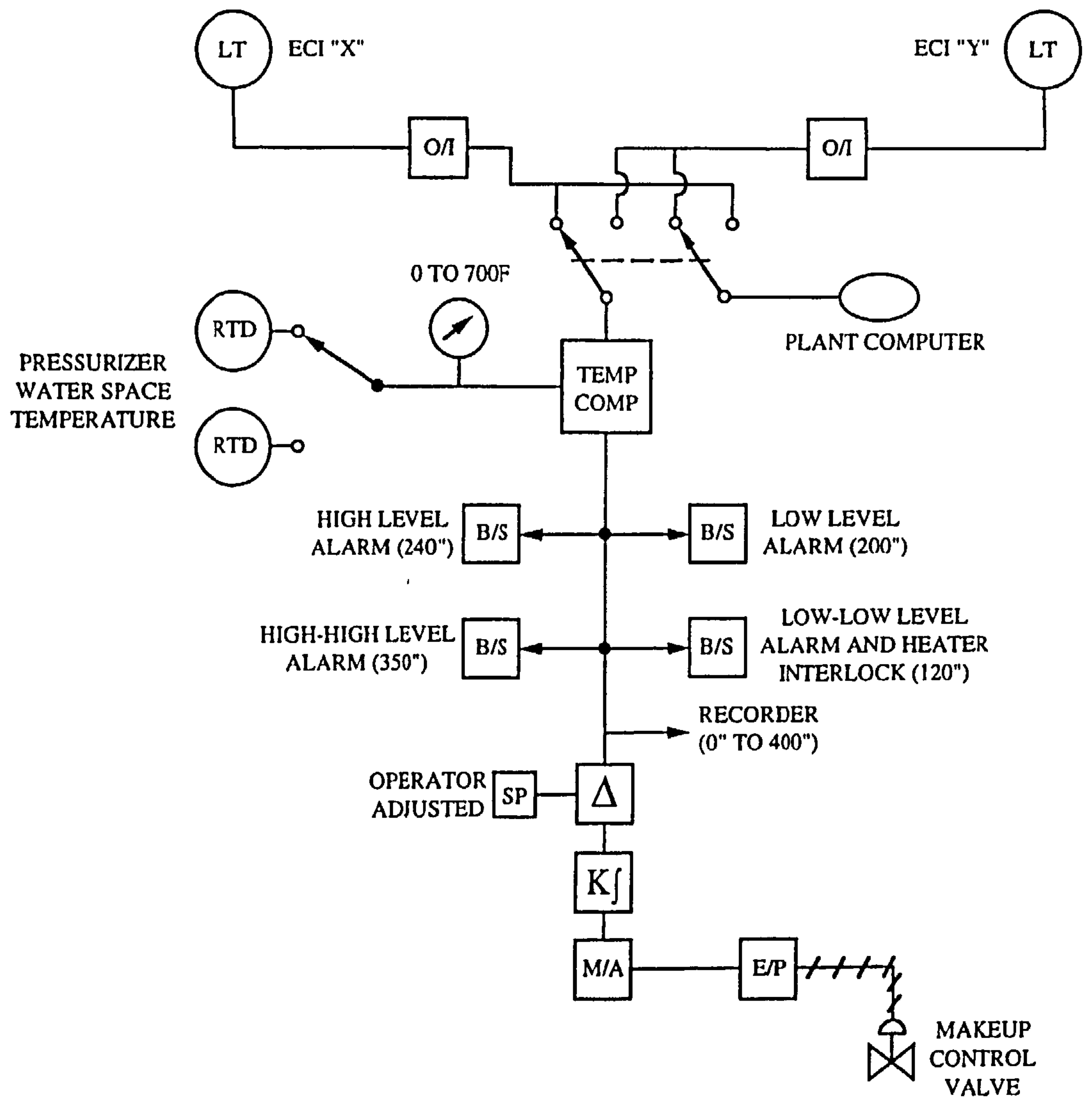

Figure 8.1-9 Pressurizer Level Control

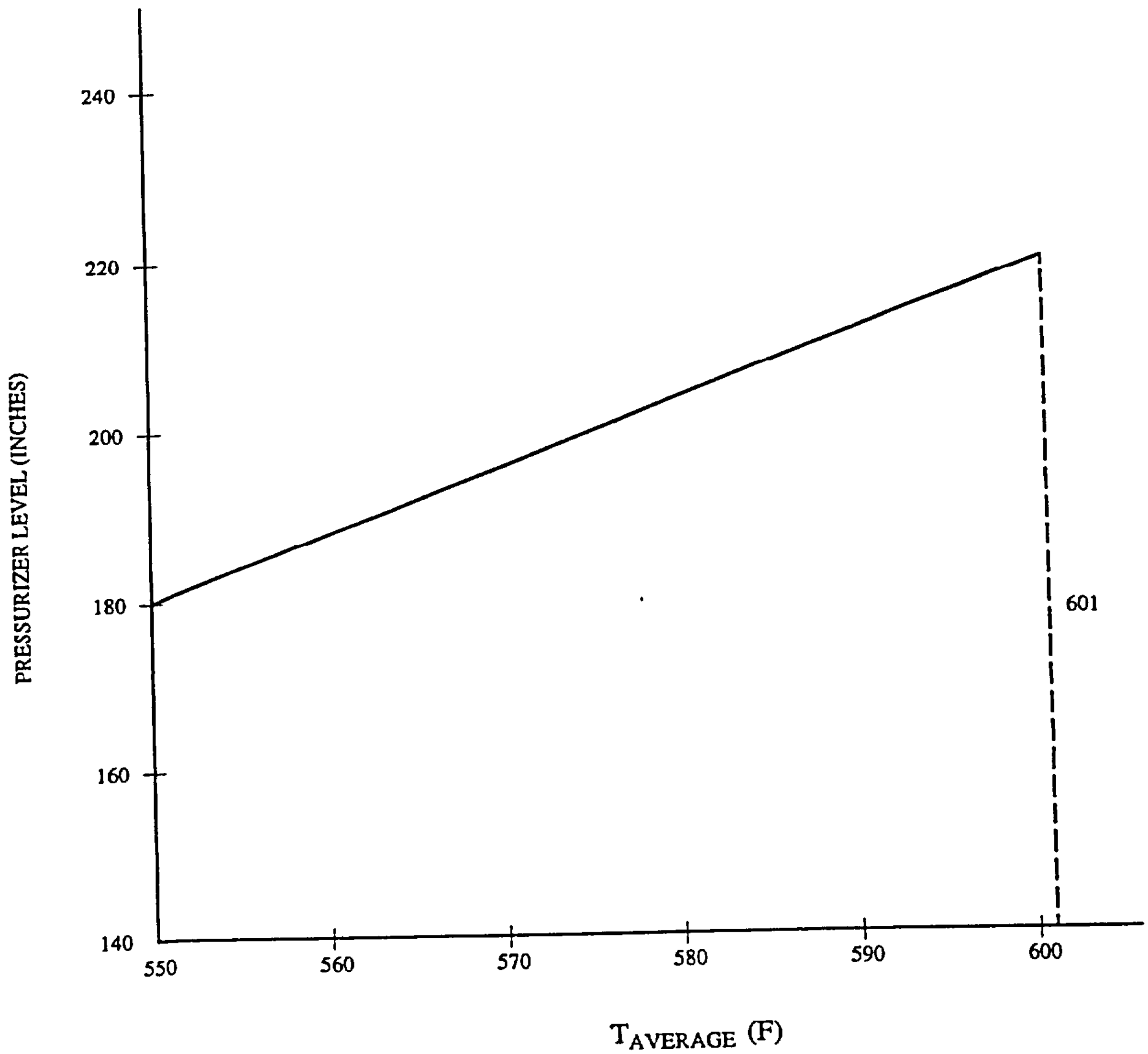

Figure 8.1-10 Typical Pressurizer Level Program

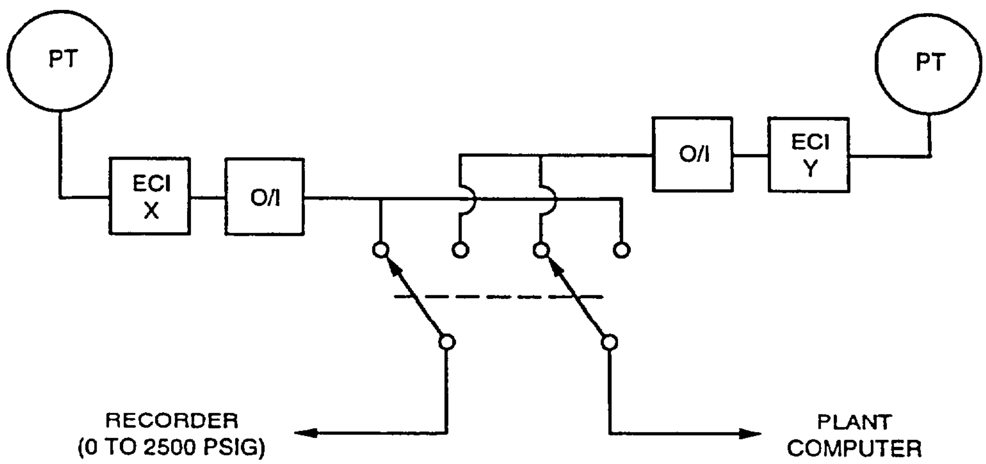

Figure 8.1-11 Wide Range Pressurizer Pressure

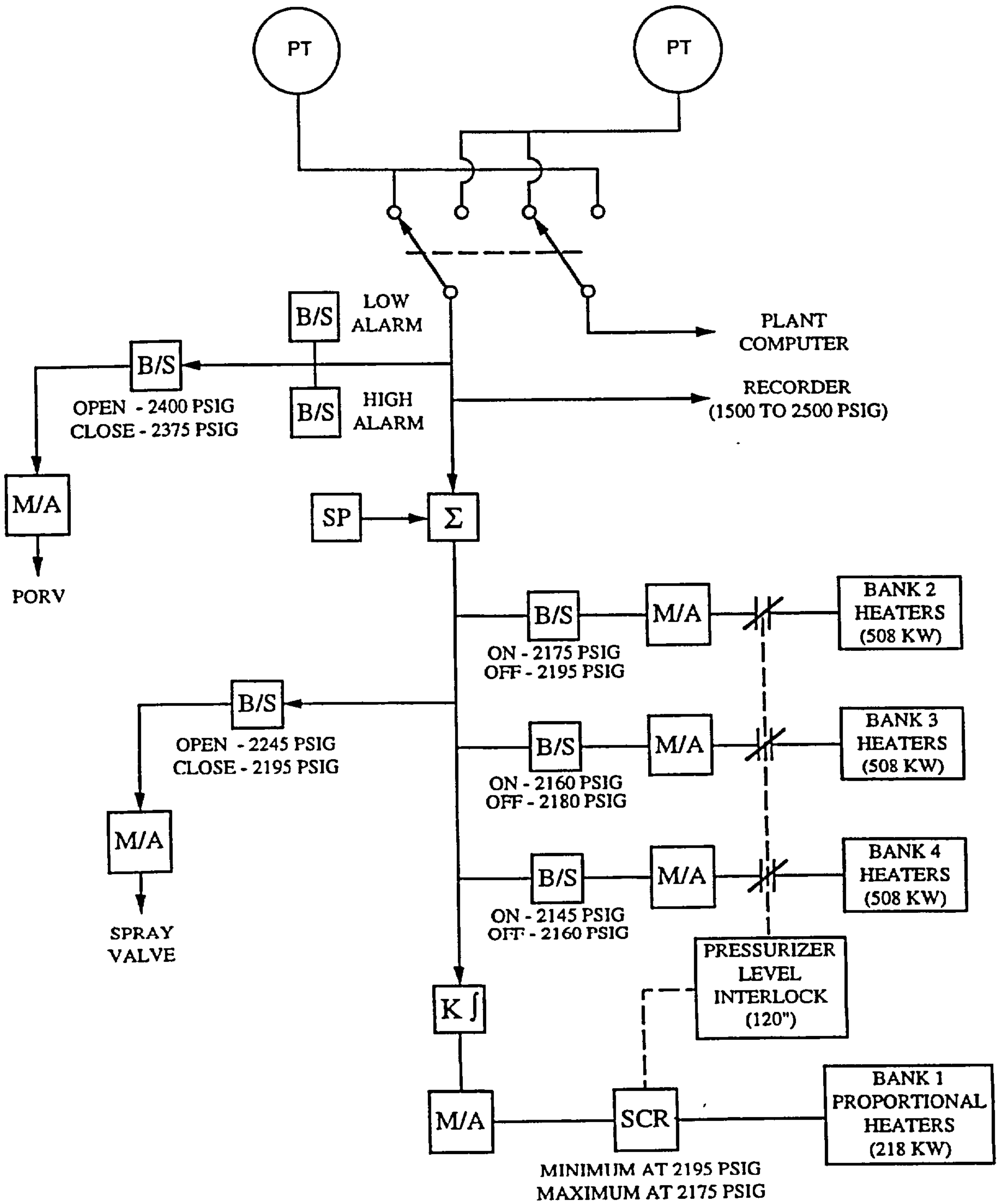

Figure 8.1-12 Narrow Range Pressurizer Pressure

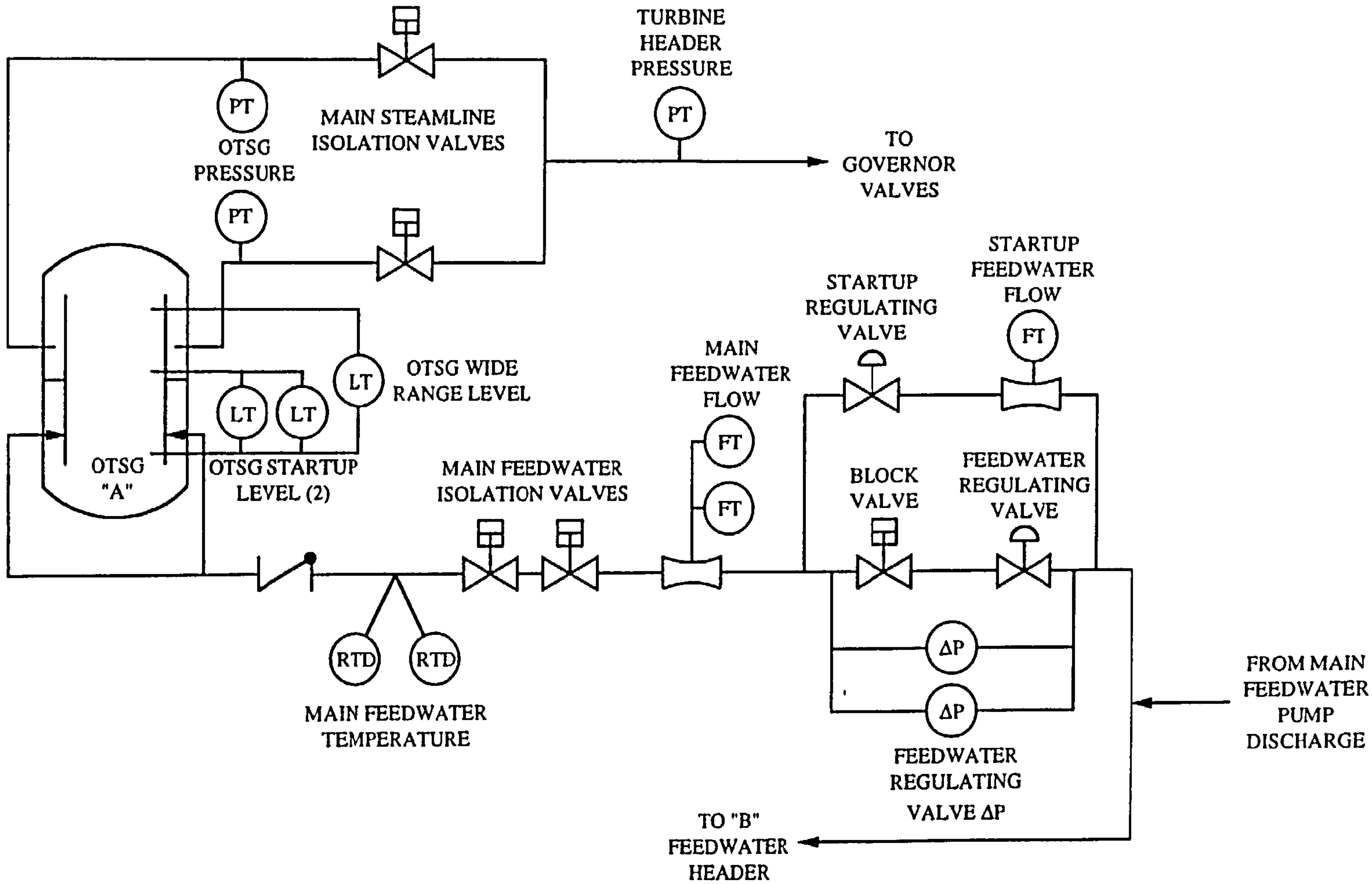

Figure 8.1-13 Feedwater System Instrumentation Locations

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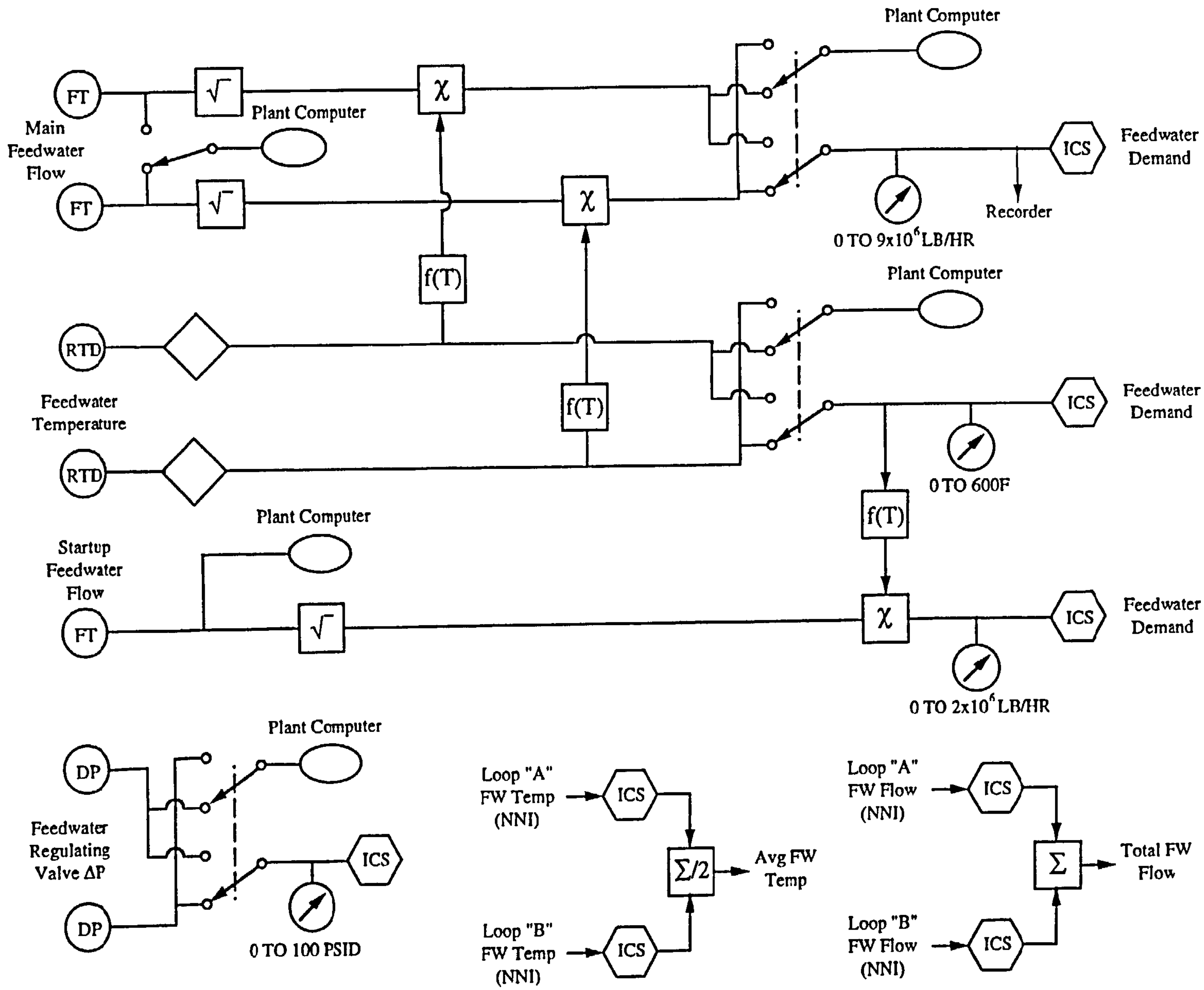

Figure 8.1-14 Feedwater Instrumentation

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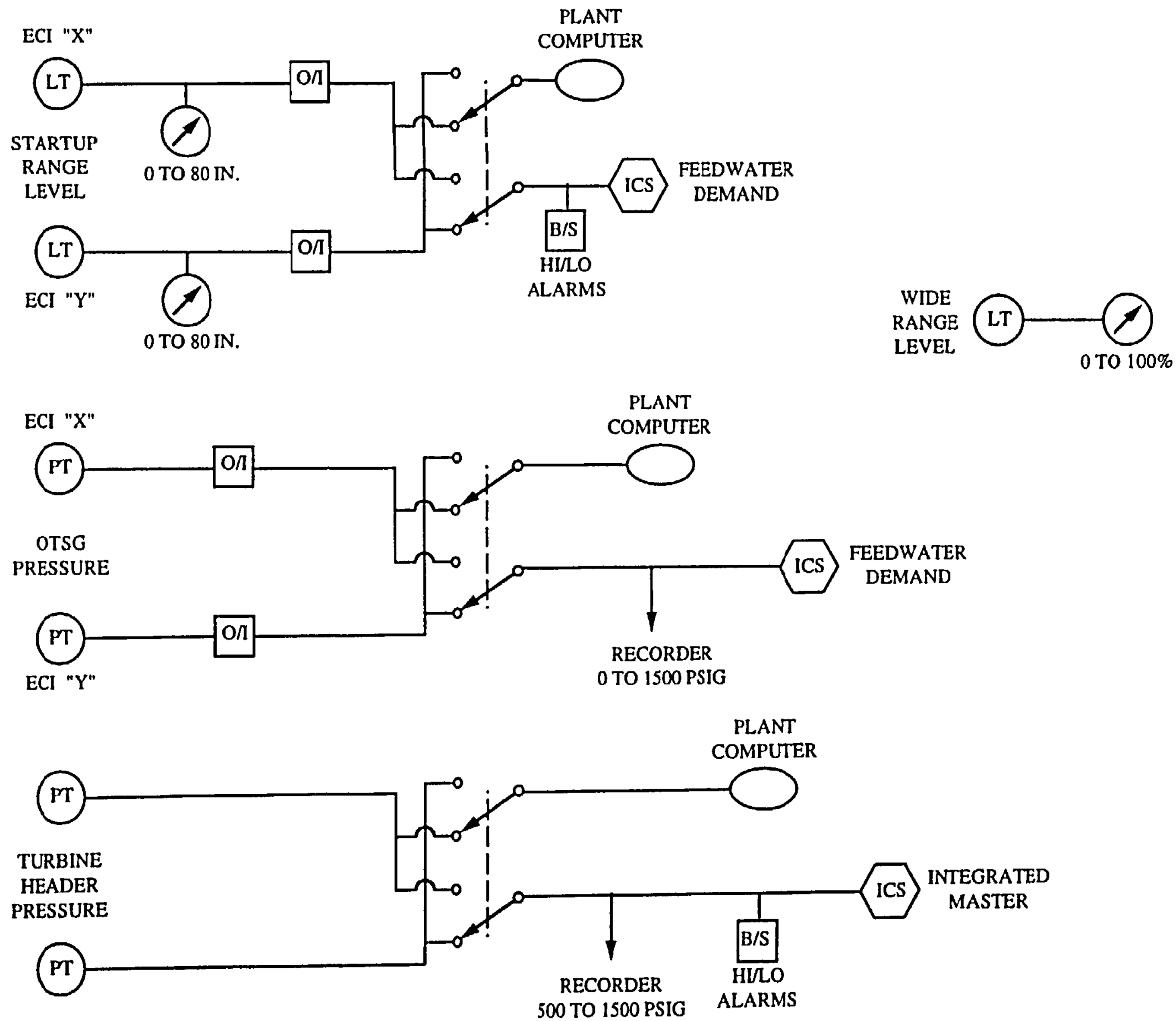

Figure 8.1-15 Steam System Instrumentation

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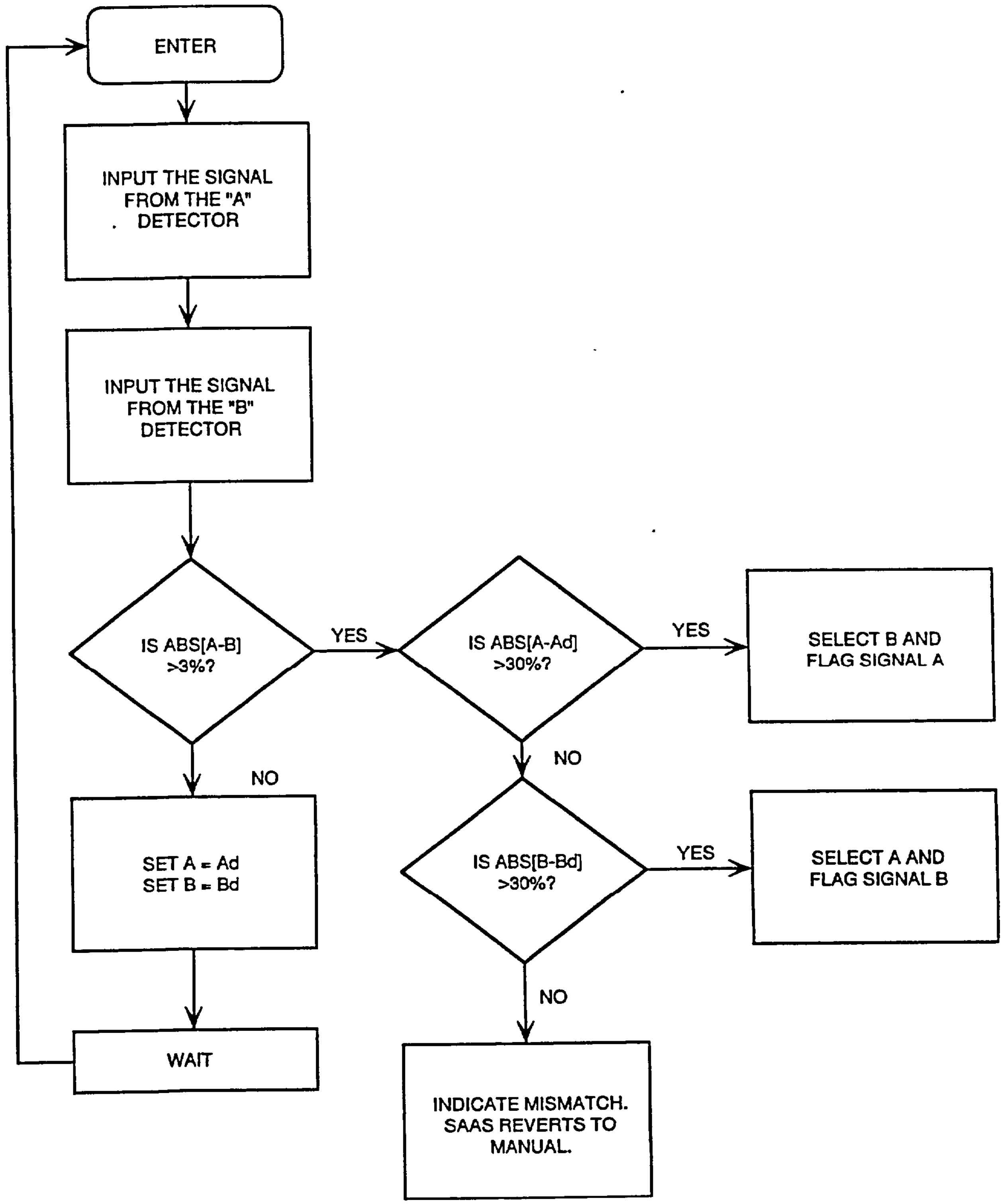

Figure 8.1-16 Smart Analog Signal Select System

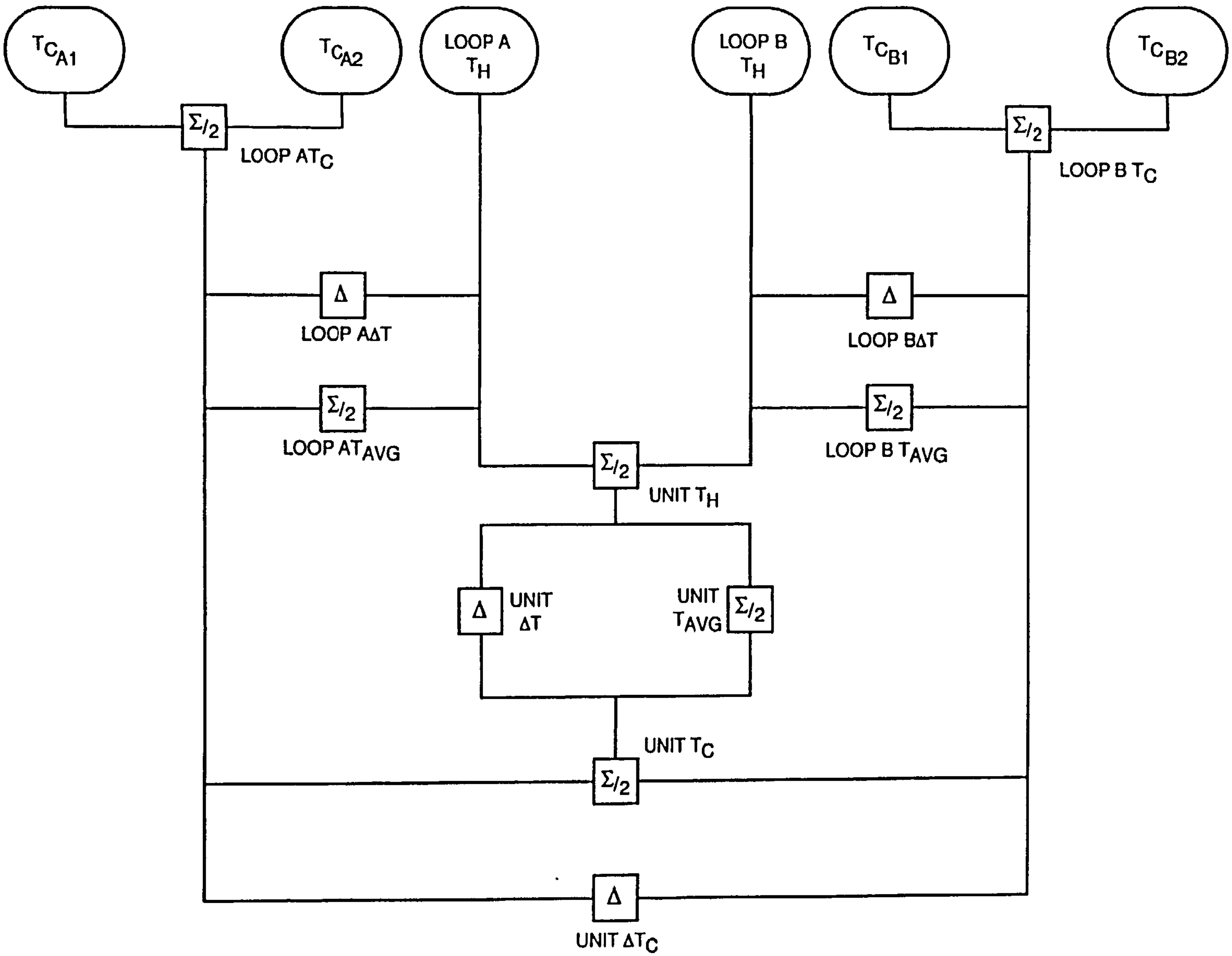

Figure 8.1-17 Non-Nuclear Instrumentation Reactor Coolant System Temperatures Simplified Diagram

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8.2 ESSENTIAL CONTROLS AND INSTRUMENTATION

Learning Objectives:

1. State the function of the essential controls and instrumentation system.

2. Explain how the wide-range pressure signal is used in the decay heat removal system.

3. Explain how the once-through steam generator level is used in the auxiliary feedwater flow control circuitry.

8.2.1 Introduction

The essential controls and instrumentation (ECI) system is a collection of instrumentation that functions to provide the indication, control, and interlock features required to place the plant in a safe shutdown condition. A safe shutdown condition is defined as the condition wherein the reactor is at least 1% ΔK/K shut down, with the reactor coolant system (RCS) in hot or cold shutdown, depending on the initial plant status that exists when the requirement for safe shutdown is initiated. Furthermore, General Design Criterion 19 of Appendix A of 10 CFR 50 requires that instrumentation and controls be installed to place and maintain the plant in hot shutdown in a location(s) outside the main control room, and, by the use of suitable procedures, the instrumentation and controls must have the capability of placing the plant in cold shutdown. To satisfy these requirements, the ECI system supplies instrumentation and controls in both the main and auxiliary control rooms. The auxiliary control room is located outside the main control room. In addition to the requirements listed above, the ECI system instrumentation is designed to remain operable following a loss-of-coolant accident.

To satisfy these requirements, redundancy and separation have been designed into the ECI system. First, the system is separated into redundant channels, ECI X and ECI Y. Each channel is powered from a separate, battery-backed, 120-vac power source. Next, plant process variables are measured by physically independent sensors, and the sensor instrument strings are also physically separated. Finally, the outputs of the instrument displays and controls are isolated from each other by either buffer isolation or fiber optic isolation.

This section describes the various indication, interlocks, and controls supplied by the ECI system.

8.2.2 Primary Plant Essential Controls and Instrumentation

8.2.2.1 Reactor Coolant Temperatures

Dedicated resistance temperature detectors (RTDs) are used to provide an input to the system (Figure 8.2-1). Narrow-range temperature input is supplied from the RCS hot legs, and wide- range temperature input is supplied from the RCS cold legs.

The narrow-range (530 to 650°F) signal for ECI X originates from an RTD located in the A hot leg and the redundant narrow-range signal for ECI Y originates from an RTD located in the B hot leg. Bridge circuits, powered from the ECI cabinets, convert the resistance of the RTD to a temperature signal. Each temperature signal is fed through a buffer module and supplied to a recorder and meter in the main control room and to a meter in the auxiliary control room. The supply to each of these display devices contains a buffer module to prevent a fault in a single display from affecting all indications. The narrow-range temperature signal is used by the operator to maintain hot shutdown conditions and to analyze accident conditions.

The wide-range (50 to 650°F) temperature signal is supplied from an RTD located in one of the reactor coolant pump (RCP) discharges in each loop. ECI X receives an input from loop B, and ECI Y receives an input from loop A. The circuitry for wide-range ECI temperature is identical to the narrow-range temperature circuitry that is described above. Wide-range temperature input is required for placing the plant in cold shutdown.

Both narrow- and wide-range temperature inputs transmit signals to the non-nuclear instrumentation system through optical isolators.

8.2.2.2 Pressurizer Level (Figure 8.2-2)

Two ECI-powered transmitters, one for ECI X and one for ECI Y, are used to sense pressurizer level. The 4- to 20-ma transmitter output is supplied to a buffer module that converts the current signal to a voltage signal with a range of -10 to 0 to +10 v. This voltage range represents a 0- to 400-in. pressurizer level and is supplied to redundant indicators in the main and auxiliary control rooms. ECI Y also inputs a signal to a main control room recorder. Buffer modules are installed to provide isolation between indicating devices. Each transmitter supplies a pressurizer level signal to the non-nuclear instrumentation system through an optical isolator.

Pressurizer level indication is necessary for the maintenance of RCS inventory during hot or cold shutdown and as an indication during accident situations.

8.2.2.3 Wide-Range Pressurizer Pressure

Wide-range (0 to 2500 psig) pressure is sensed by two ECI pressurizer pressure transmitters (Figure 8.2-3). One transmitter is dedicated to ECI X, and the other transmitter is dedicated to ECI Y. The 4- to 20-ma output of the transmitters is converted to signals with a range of -10 to 0 to +10 v by buffer modules located in the ECI X and ECI Y cabinets. The voltage signal is then transmitted through isolation buffers to pressure indicators located in the main and auxiliary control rooms. The non-nuclear instrumentation system receives wide-range pressurizer pressure inputs from the ECI cabinets through optical isolation. Wide-range pressurizer pressure indication is used by the operator to maintain the plant in hot or cold shutdown and to control the plant during the transition between these two conditions. Pressure indication is also necessary during post-accident conditions.

In addition to pressure indication, wide-range pressure input provides an interlock to the decay heat removal (DHR) system RCS suction valves. This interlock will automatically close the suction valves if RCS pressure exceeds 400 psig to prevent overpressurization of the DHR piping. The ECI system provides separate interlocking signals; that is, ECI X closes V-25A in the suction supply to DHR pump A, and ECI Y closes V-26B. Redundancy in DHR suction isolation is ensured by closing V-23A and V-24B with signals supplied by the engineered safety features actuation system.

The wide-range pressure transmitters also provide inputs to the core flood tank (CFT) isolation valve interlocks. An alarm is generated if pressurizer pressure is less than 650 psig and the isolation valves are open. This alarm alerts the operator to shut the valves so that the CFTs will not discharge to the RCS during a plant cooldown and depressurization. Also, the isolation valves will receive an open signal when RCS pressure increases to 750 psig during a plant heatup, in order to place the CFT system in its normal at-power configuration. The ECI X pressure transmitter supplies the interlocks for CFT A isolation valve V-31A, and the ECI Y pressure transmitter supplies the interlocks for CFT B isolation valve V-32B.

8.2.2.4 Miscellaneous Primary Plant Controls and Instrumentation

Various pressure, flow, and level indications are supplied by the ECI system to allow the monitoring of emergency core cooling systems and their auxiliaries. These indications include low-pressure injection flow, sodium hydroxide tank level, and core flooding tank pressures and levels. A complete listing of ECI system instrumentation is found in Table 8.2-1.

Besides the indication supplied by the ECI system, hand controllers for decay heat cooler outlet and bypass valves are installed in both the main and auxiliary control rooms. This ECI control is necessary for the second part of plant cooldown.

8.2.3 Secondary Plant Controls and Instrumentation

8.2.3.1 Steam Pressure

The sensing of main steam pressure for each OTSG is identical; therefore, only the pressure sensing and indication for the A OTSG is discussed in this section (Figure 8.2-4).

Two pressure transmitters, one associated with ECI X and one associated with ECI Y, are used to sense main steam pressure. The transmitters detect pressure on the OTSG outlet headers, one transmitter per outlet header.

The ECI Y transmitter supplies indicators in the main control room and in the auxiliary control room. The ECI X transmitter supplies indicators in the main and auxiliary control rooms, a recorder in the control room, and the control scheme for the modulating atmospheric dump valves.

The Class 1E modulating atmospheric dump valves are controlled by a proportional-integral controller that receives an error signal from a difference amplifier (Δ). The inputs to the difference amplifier are actual steam pressure and a setpoint (1205 psig). The differences between these inputs are acted on by the proportional-integral controller to cause actuation of the dump valves. Manual/ automatic (M/A) controllers, located in the main and auxiliary control rooms, provide a method of manually controlling steam pressure. The auxiliary control room M/A overrides the main control room station. From the M/A control station, the control signal travels to an electrical-to-pneumatic (E/P) converter that is used to modulate the air signals supplied to the valves.

The indication and control of steam pressure is required for the mitigation of accidents and for establishing safe shutdown conditions.

8.2.3.2 Once-Through Steam Generator Level

Redundant startup range level transmitters powered from separate ECI cabinets are installed on each OTSG. The circuitry (Fig. 8.2-5)in each ECI cabi is identical, and only the ECI X circuitry is described below.

The level transmitter signal for each OTSG is supplied to a buffer amplifier that converts its 4- to 20-ma output to a signal with a range of -10 to 0 to +10 v. The voltage signal is then supplied to main and auxiliary control room indicators through isolation buffer units and to the non-nuclear instrumentation system through optical isolators. The voltage output is also supplied to the auxiliary feedwater flow control circuitry.

The control of auxiliary feedwater is accomplished by comparing actual OTSG level with level setpoint (2 or 6 ft) in a difference amplifier (Δ). The output, an error signal, of the difference amplifier is supplied to a proportional-integral controller that, in turn, supplies the control of the auxiliary feedwater flow control valves. Manual/automatic (M/A) stations located in the main and auxiliary control rooms allow manual operator control of OTSG level. Redundancy of level control signals is shown in Figure 8.2-6, ECI X supplies A OTSG level control through LCV-4025 and B OTSG level control through LCV-4009. ECI Y controls A OTSG level through LCV-4026 and B OTSG level through LCV-4007. With redundant flow control valves and signal sources, level control is ensured even if one complete ECI system is lost.

8.2.4 Summary

ECI provides indication, control, and interlock features required to maintain the plant in a safe shutdown condition. ECI has two redundant channels, and each is battery-backed. Indication and control is provided in the main and auxiliary control rooms.

TABLE 8.2-1 ESSENTIAL CONTROLS AND INSTRUMENTATION

Measured parameter	Indicator range
Pressurizer level, inches of water	0-400
Pressurizer pressure, psig	0-2500
Reactor Coolant outlet temperature, loop A, °F	530-650
Reactor Coolant outlet temperature, loop B, °F	530-650
Reactor Coolant inlet temperature, loop A, °F	50-650
Reactor Coolant inlet temperature, loop B, °F	50-650
Steam generator level, loop A, inches of water	0-80
Steam genenerator level, loop B, inches of water	0-80
Main steam pressure, loop A, psig	0-1500
Main steam pressure, loop B, psig	0-1500
High-pressure injection flow, loop A, gpm	0-400
High-pressure injection flow, loop B, gpm	0-400
Core flooding tank A level, feet of water	0-21
Core flooding tank B level, feet of water	0-21
Core flooding tank A pressure, psig	0-800
Core flooding tank B pressure, psig	0-800
Decay heat removal heat exchanger outlet flow A, gpm	0-7000
Decay heat removal heat exchanger outlet flow B, gpm	0-7000
Reactor building spray flow A, gpm	0-3000
Reactor building spray flow B, gpm	0-3000
Borated water storage tank level, feet of water	0-55
Reactor building pressure, psia	0-60
Reactor building temperature, °F	0-450
Sodium hydroxide tank level, feet of water	0-40
Reactor building emergency sump level, inches of water	0-400
Reactor building emergency sump temperature, °F	50-300

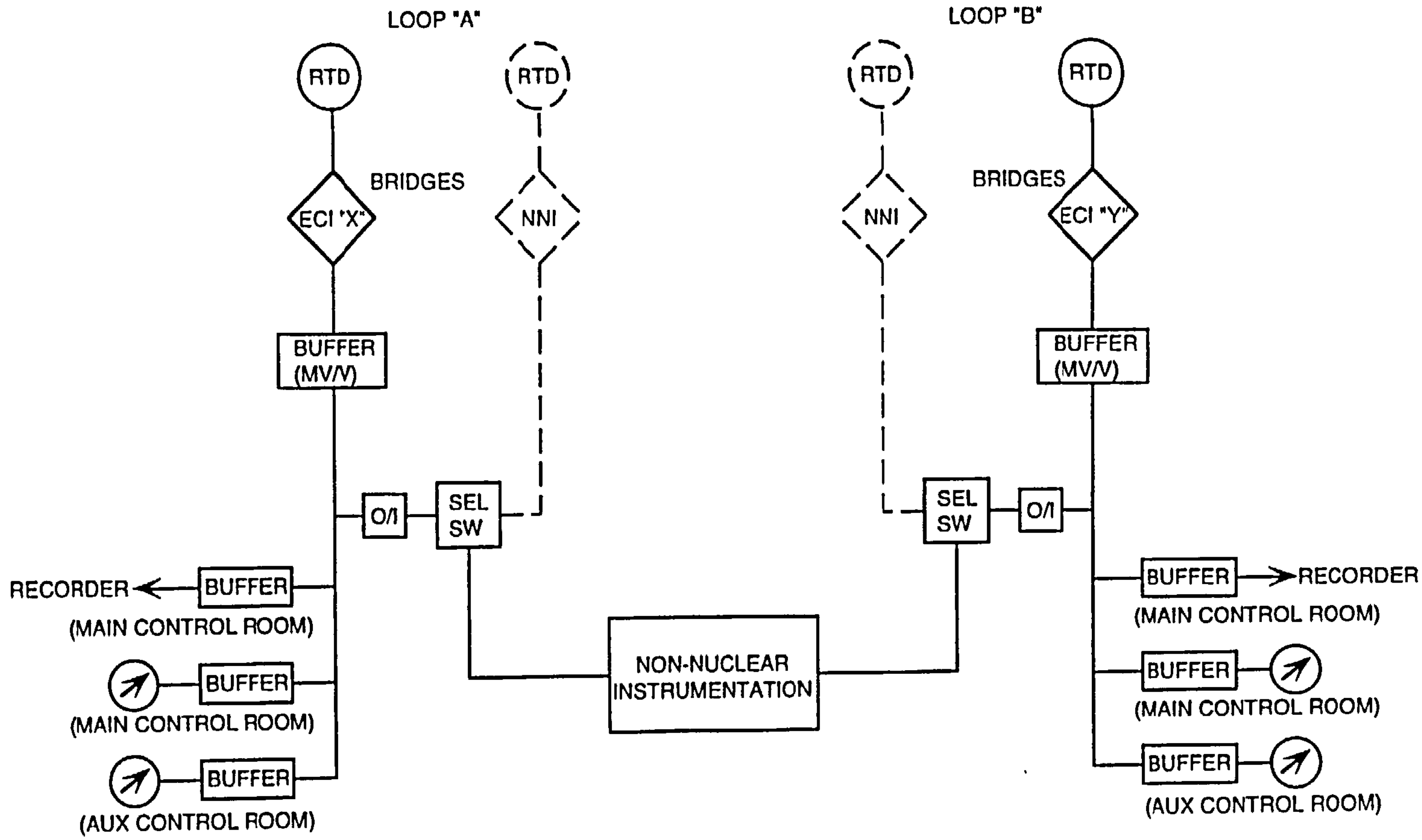

Figure 8.2-1 Reactor Coolant Temperature Block Diagram (Typically)

1096

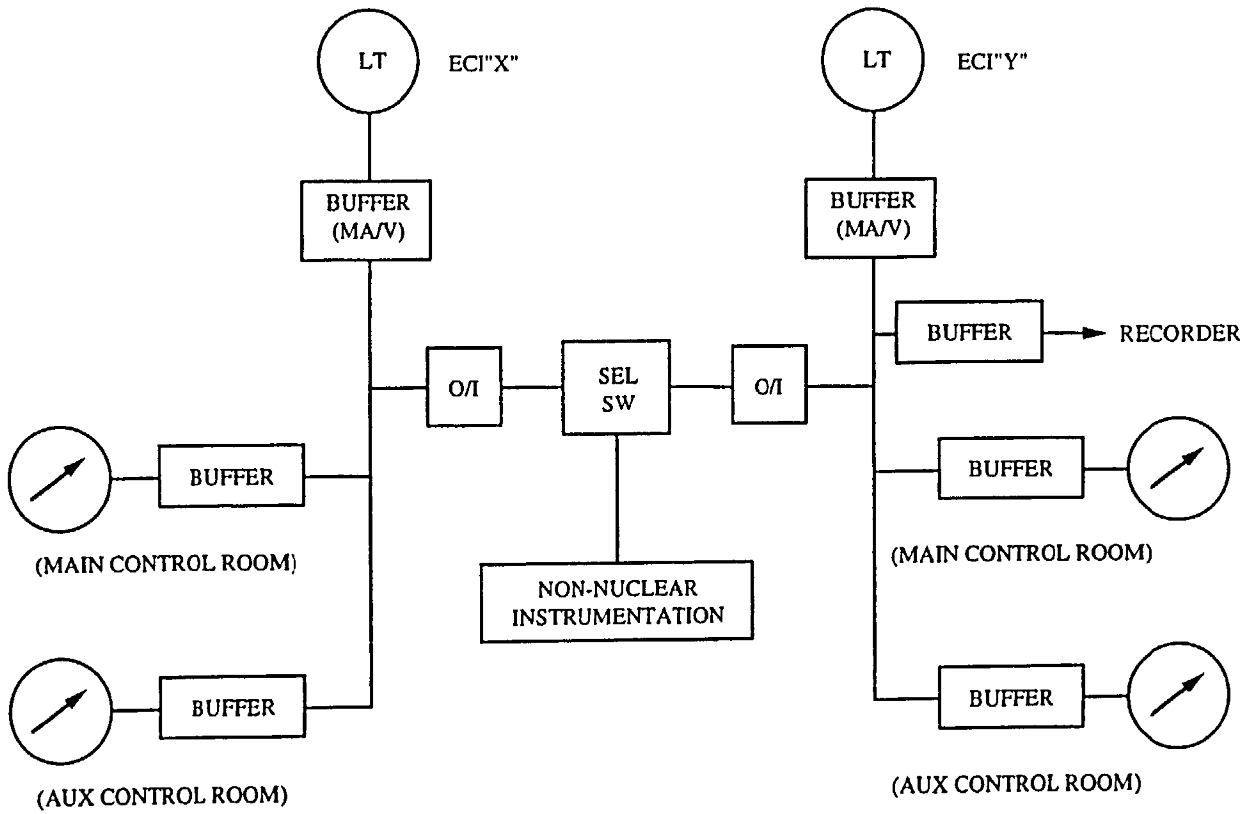

Figure 8.2-2 Pressurizer Level Indication

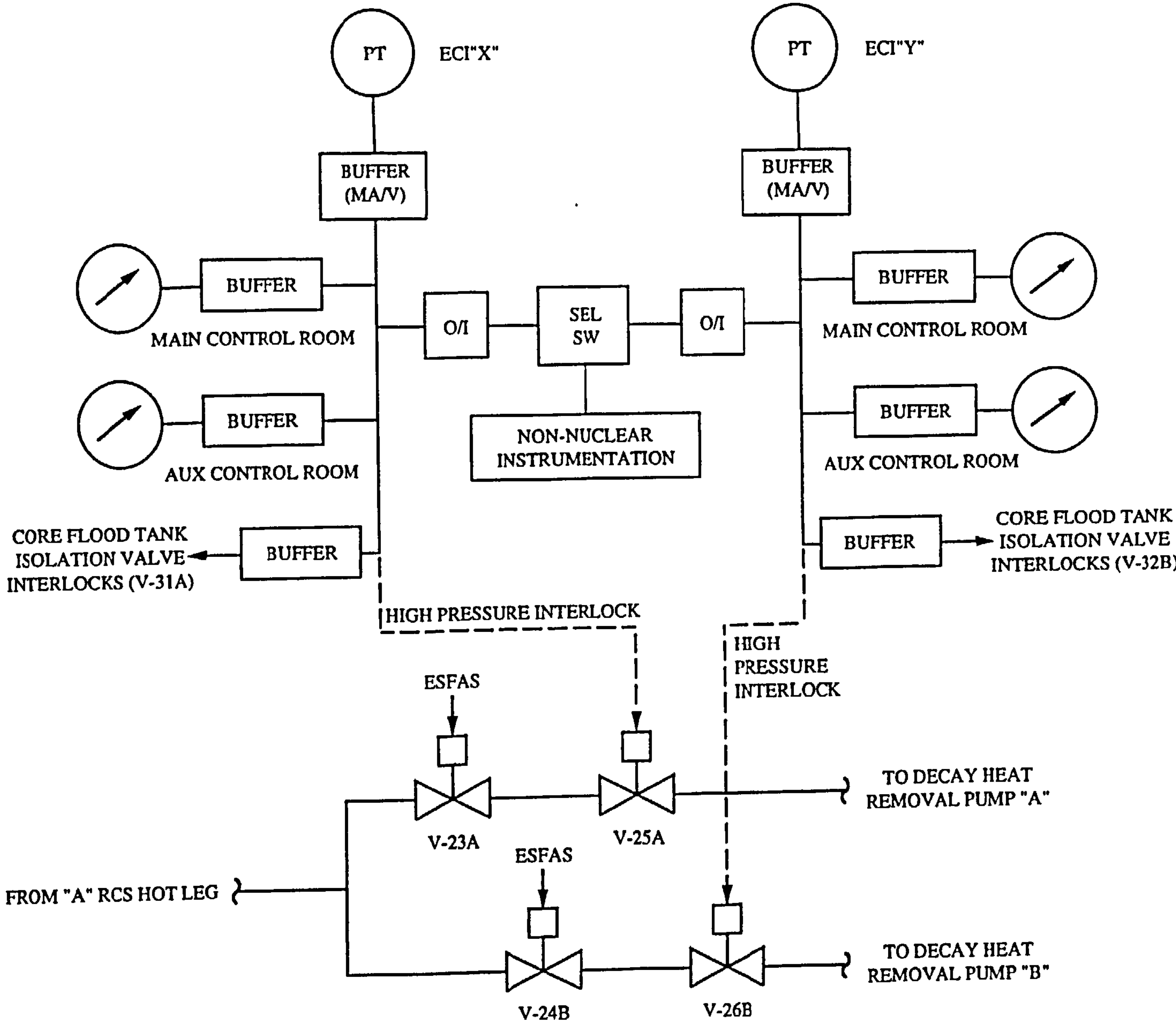

Figure 8.2-3 Wide Range Pressurizer Pressure

0292

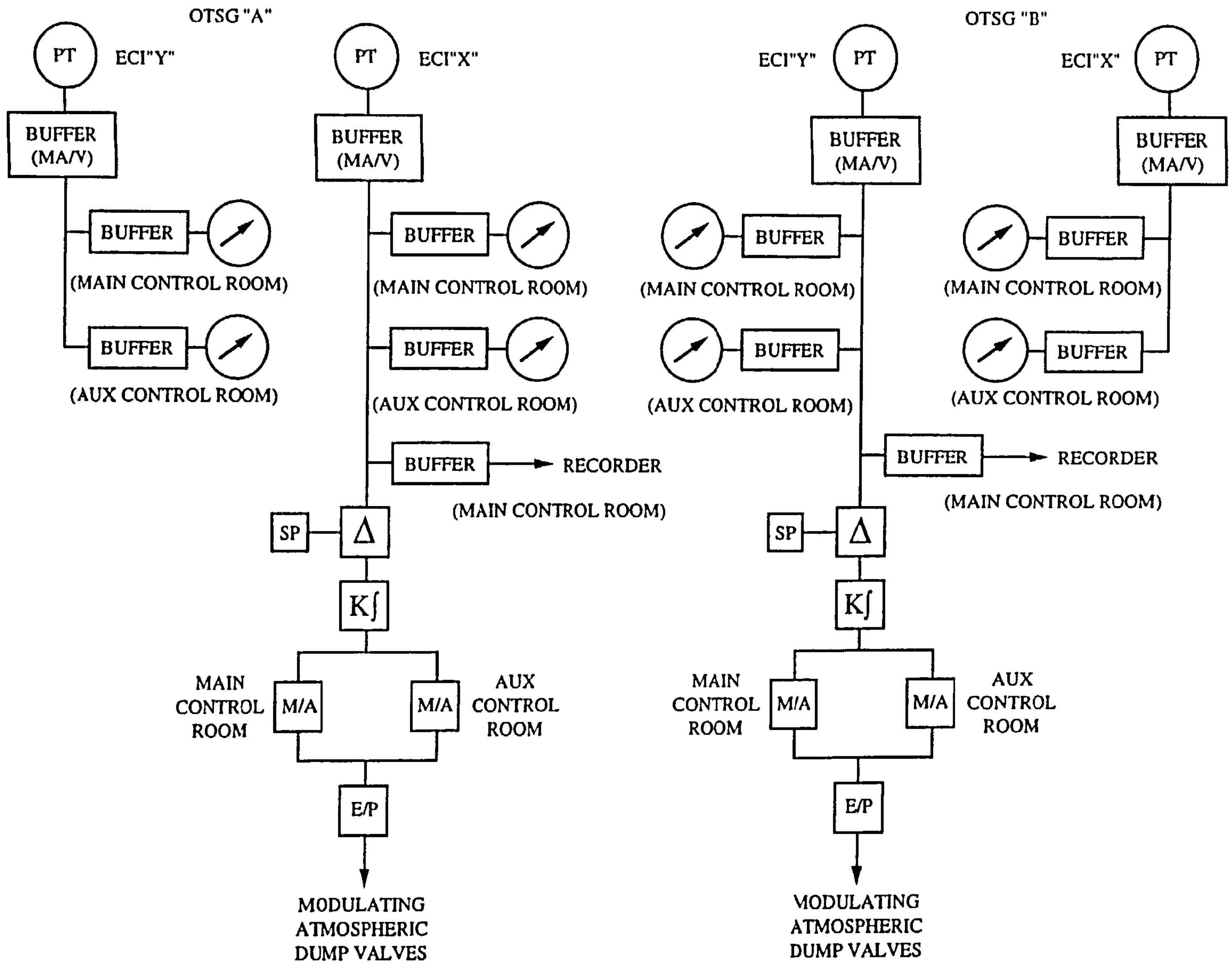

Figure 8.2-4 Steam Pressure

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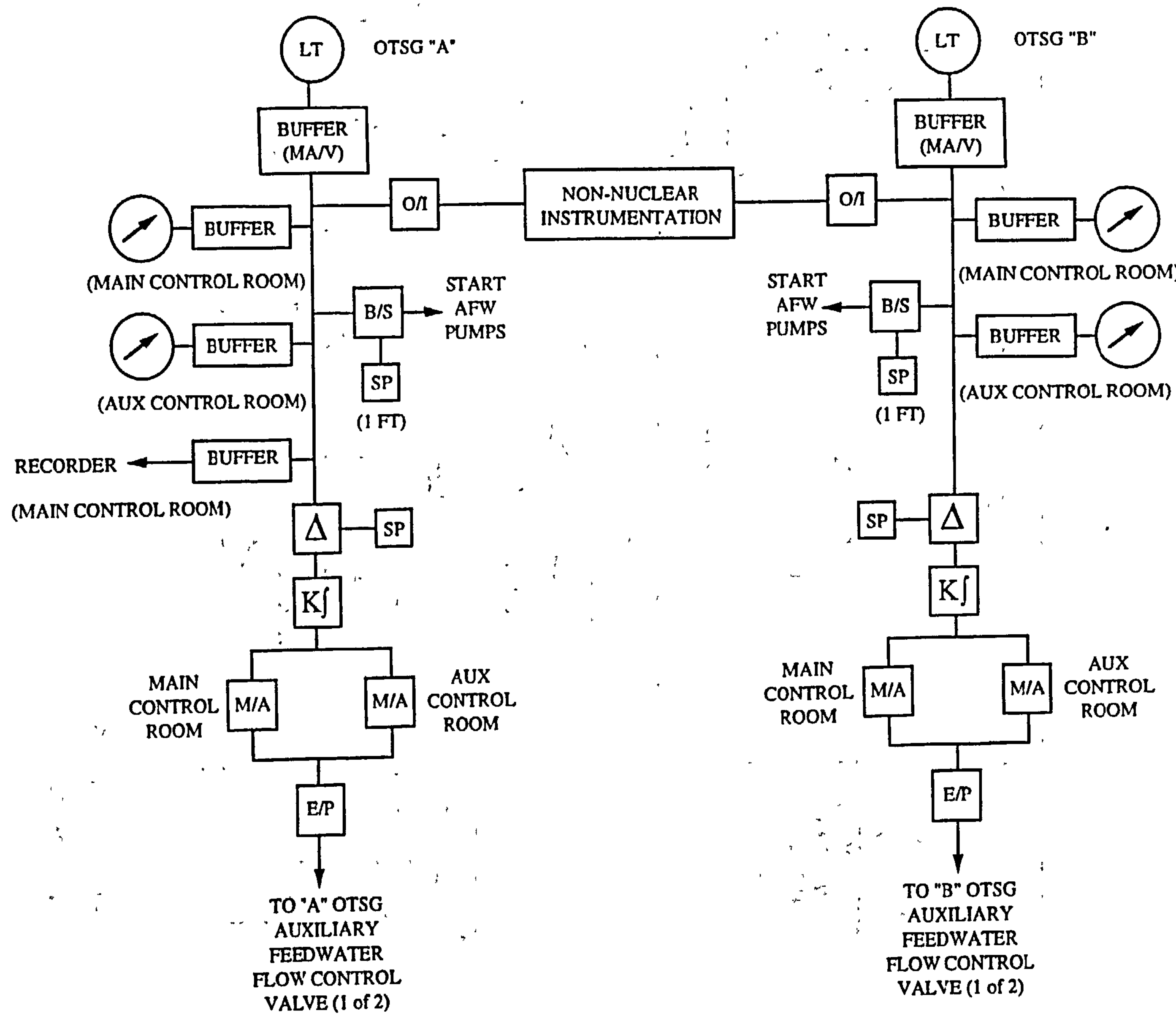

Figure 8.2-5 Steam Generator Level (Typical of One ECI Channel)

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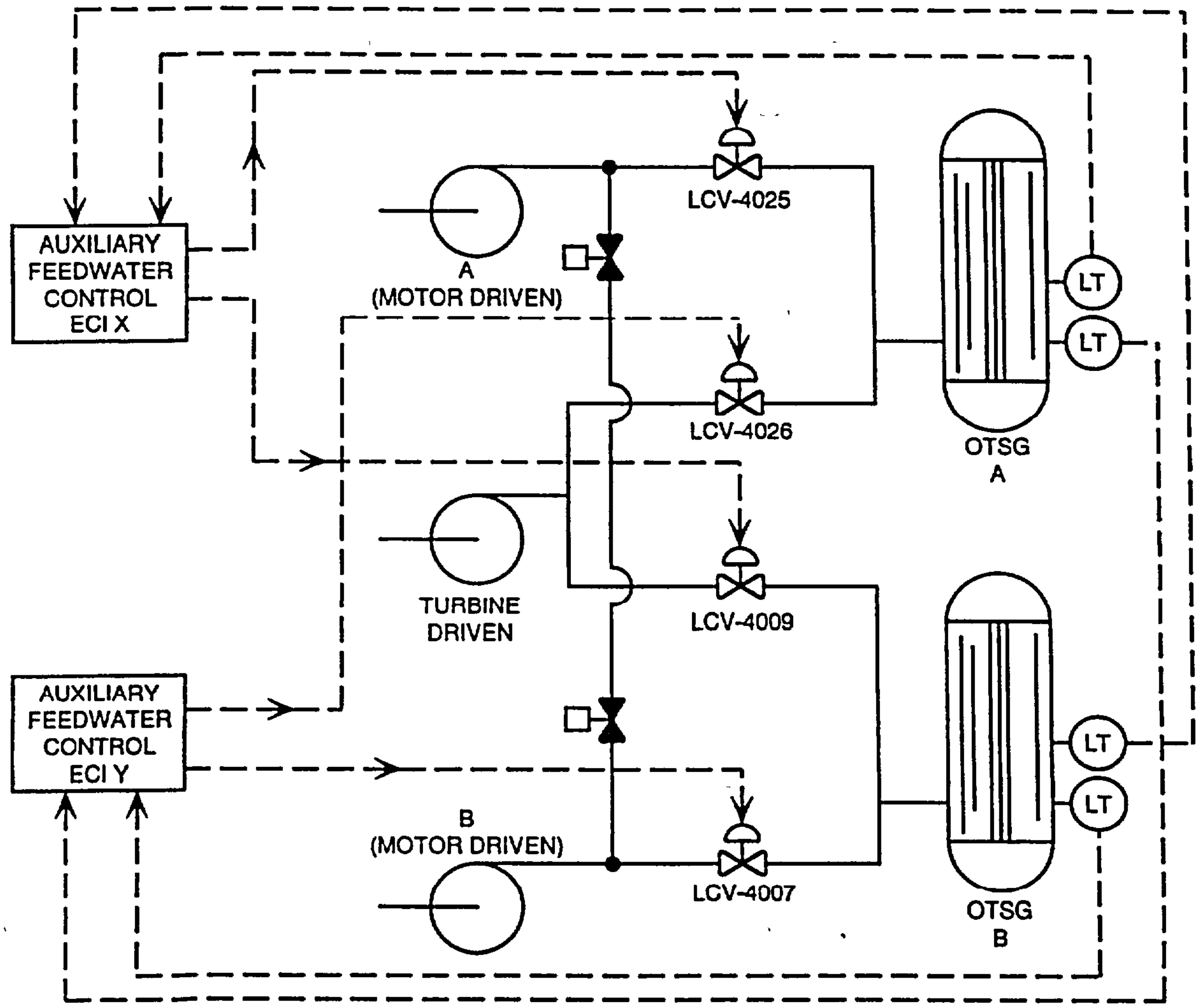
0896



LT = LEVEL TRANSMITTER

LCV = LEVEL CONTROL VALVE

Figure 8.2-6 Auxiliary Feedwater Control

BABCOCK AND WILCOX
CROSS TRAINING MANUAL

CHAPTER 9 Integrated Control System

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9.0 INTEGRATED CONTROL SYSTEM

Learning Objectives:

1. Explain the function of the following Integrated Control System (ICS) subassemblies:

    a. Unit load demand (ULD)
    b. Integrated master (IM)
    c. Feedwater demand
    d. Reactor demand

2. Define the following terms:

    a. Track
    b. Runback
    c. Cross limits

3. With the use of a block diagram of the ICS, discuss the following:

    a. Normal power increase and decrease
    b. Runbacks
    c. Cross limits
    d. Placing an ICS hand/auto station in manual
    e. Load rejection
    f. Turbine trip
    g. Reactor trip

9.1 Introduction

The integrated control system (ICS) has as its basic requirement the matching of generated electrical megawatts with demanded electrical megawatts. As shown in Figure 9-1, the ICS accomplishes this requirement through four subassemblies: the unit load demand, the integrated master, the feedwater demand, and the reactor demand. The unit load demand functions as a setpoint generator for the ICS. The integrated master receives the megawatt setpoint from the unit load demand and translates this demand signal into signals for feedwater and reactor control. In addition, the integrated master controls the electrical generation of the turbine generator. In the feedwater demand subassembly, the megawatt demand signal, converted to a feedwater demand in the integrated master, controls the amount of feedwater supplied to the once-through steam generators. The reactor demand subassembly moves the reactor's control rods in or out in response to the megawatt demand signal, and also controls the average reactor coolant system temperature. Section 9.2 discusses the four subassemblies; Section 9.3 discusses ICS operations.

9.2 General Description

The basic integrated control system is shown in Figure 9-2. Several terms used in this chapter are defined below.

1. Track : Track is defined as a condition during which actual generated megawatts are substituted for the megawatt demand signal. This is shown in Figure 9-2 by transfer relay T_1. During normal operation, T_1 supplies the megawatt demand signal from the ULD hand/automatic (H/A) station to the other ULD subassembly components. In track, T_1 substitutes actual generated megawatts (Mwg) for the megawatt demand signal. Track is initiated when the ICS senses that fully automatic control has somehow been inhibited. The following conditions place the unit in track :

    a. reactor trip
    b. generator output breakers open
    c. any major ICS hand/automatic station in hand (manual):
        (1) reactor demand
        (2) SG/RX master

(3) both loop feedwater demands
d. Diamond rod control in manual
e. turbine electro-hydraulic control in manual
f. feedwater flow greater than feedwater demand by 5%
g. reactor or feedwater cross limits

2. Runback: A runback is an automatic reduction in unit load and occurs when necessary power generation equipment is lost or its capacity is reduced. The runback condition reduces load at a rate proportional to the severity of the loss of generation equipment and also sets a maximum allowable load limit into the ULD. Once a runback condition is sensed, unit load is reduced at the predetermined rate until load is below the maximum allowed value for the runback rate. Conditions that cause a runback are given in Table 9-1. If an asymmetric rod condition is assumed, then a runback rate of 30% per minute will be transferred to the remainder of the ICS, and unit load will be reduced to less than 60% (i.e., 60% of the 100% generated megawatt value). If an attempt to exceed 60% should occur, then another runback condition would exist with load being reduced to less than 60% at 30% per minute.

9.2.1 Unit Load Demand

The unit load demand (ULD) provides the ICS with the ability to sense both the desired amount of electrical generation and the desired rate of change of electrical generation. These variables are placed into the system by the plant operator and are transmitted to the remainder of the system, resulting in the generation of the desired amount of electrical load. The operator inputs the megawatt demand from 0 to 1350 Mw electrical (Mwe) by changing the setpoint (SP) adjustment associated with the unit load demand hand/automatic (H/A) station shown in Figure 9-2. After this input is made, the operator must also input the desired rate of load change. The operator determines unit electrical output rate of change from 0.5% per minute to 5% per minute by changing the setpoint supplied to the rate limiter. (Below 15% power a maximum rate of change of 0.75% per minute is imposed.) Other required operator inputs into the ULD are the high- and low-load limits. These two limits allow the maneuvering of the unit between their setpoints. Generally, the low-load limit is set to approximately 15% of unit generation capability, and the high-load limit is set at the 100% load value; however, the operator may input any value between 0 and 100% as a setpoint into either load limit. An example of a setpoint that could be input into the high-load limit is the power restriction associated with only one operable main feedwater pump. The maximum amount of feedwater flow that one pump can deliver is 60%; therefore, this value can be placed into the high-load limit as a setpoint to prevent inadvertent load requests that are greater than 60%. Demands greater than the high-load limit are automatically reduced to the high-load limit at the operator selected rate of load change. As previously stated, the low-load limit is usually set at 15%. Below 15% load, unit stability is reduced (the turbine may not be loaded, and input signal magnitude is very small), and fully automatic operation may be prohibited. If the load is less than the low-load limit, it will be increased automatically to the low-load value at the operator selected rate of load change. During runback or tracking conditions, the low-load limit is ignored by the system.

9.2.1.1 Frequency Correction

Frequency correction is the increase or decrease in generated megawatts based on grid frequency. A decrease in grid frequency is indicative of a grid load greater than grid generation. The turbine electro-hydraulic control system senses this condition and opens the turbine control valves, increasing steam flow to the turbine. The increase in steam flow causes the turbine to pick up load. When a particular load value is placed into the ICS, the ICS will try to reduce the load back to setpoint as unit load is increased on a decrease in grid frequency. This reduction in load is the opposite of the desired action; therefore, a frequency correction is applied to the ICS to add to the load demand. With frequency correction, any decrease in grid frequency will increase megawatt demand from the ULD. However, the high-load limit prevents the frequency-corrected load demand from exceeding the high-load setpoint.

9.2.1.2 Unit Load Demand Operations

Unit load demand operations can be illustrated by the following example. Assume that the unit is at 675 Mwe (50%), and it is desired to increase the unit load to 1013 Mwe (75%) at 5% per minute. At the rate-of-change station, the operator selects a rate of 5% per minute. The 75% load value is placed into the ULD H/A station. The output of the rate unit is an increasing signal changing at a rate of 5% per minute. Using this example, the output of the rate unit will reach the desired 75% load demand 5 min after the load change is initiated. From the rate unit, the signal passes to the summing amplifier ($\sum$), where frequency correction is added. The output of the summing amplifier is compared to the high- and low-load limits and the runback load limits. Since the load demand is greater than 15% and less than 100%, and no runback condition exists, the ULD subassembly is unaffected. The output of the frequency-correction summing amplifier is the megawatt demand for the turbine, the feedwater system, and the reactor. This demand signal causes simultaneous increases in generated megawatts, feedwater flow, and reactor power, and the unit will stabilize at 75% load.

With the unit at 75% load, the effects of placing the reactor demand subassembly hand/automatic station in hand and manually increasing its setpoint will be examined. Placing the reactor demand station in hand results in the ICS being placed in track. In track, actual generated megawatts are substituted as the megawatt demand signal via transfer relay T_1, and increasing the reactor demand station setpoint will result in outward rod motion, an increase in reactor power, and an increase in OTSG pressure. Increasing OTSG pressure results in further opening of the turbine control valves and an increase in generated megawatts. The output of the ULD subassembly is increased at a rate of 20% per minute, which is automatically input to the rate unit. The other ICS stations track this increase in ULD output. Simultaneously, the ULD H/A station load setpoint tracks the actual generated megawatts. As a result, when the operator completes the power change and returns the reactor demand station to automatic, the desired load (setpoint) will agree with the actual load.

Next assume that while the unit is at 75%, a feed pump trips. The feed pump trip inserts a runback signal into the ULD. The feed pump runback calls for a maximum unit load of 60% and a load decrease rate of 50% per minute. The ULD subassembly accomplishes the decrease in load demand by adding -100% to the summing amplifier ($\sum$) which precedes the rate unit, and by inputting a 50% per minute rate of decrease to the rate unit. Simultaneously, the ULD H/A station load setpoint tracks the decreasing output of the rate unit. When the ULD subassembly output no longer exceeds the feed pump runback load limit (60%), the runback inputs to the summing amplifier and the rate unit are removed. The ULD subassembly output is thus stabilized at the new demanded load of 60%.

The response of the ULD subassembly to a violation of the high- or low-load limit is similar to the runback response. If the high-load limit is exceeded, -100% is added to the summing amplifier upstream of the rate unit, the load demand is reduced at the operator-selected rate, and the load demand setpoint tracks the output of the rate unit. If the load demand is less than the low-load limit, the response is identical, except that +100% is added, and that the load demand is increased. In either case, the automatic inputs to the ULD subassembly are removed when the limit is no longer violated.

Finally, assume a load increase from 35% to 50% at a rate of 5%/min has been demanded by the operator. When the unit reaches 40%, a tracking condition occurs. Since the unit is in track, 40% becomes the unit load demand and the plant should stabilize at this load value. When the tracking condition clears, the load change must be reinstated by the operator.

In this section the generation of a setpoint, called a megawatt demand, by the ULD during normal operations, tracking operations, and runback conditions has been discussed. The following sections discuss the processing of this megawatt demand.

9.2.2 Integrated Master

The functions of the integrated master (IM) (Figure 9-2) are (1) to control the load of the turbine generator, (2) to provide a modified megawatt demand signal to the feedwater and reactor demand subassemblies, (3) to control the 22 atmospheric dump and turbine bypass valves, (4) to compensate for changes in plant efficiency in order to maintain a constant turbine load, and (5) to characterize the megawatt demand signal into feedwater and reactor demand signals. These functions, with the exception of item (5), are accomplished by controlling steam header pressure. The IM receives inputs of megawatt demand from the ULD, actual turbine load, and steam header pressure.

9.2.2.1 Generator Load Control

Steam header pressure is controlled at a constant value (1035 psia in the 205 FA units) in the B&W PWRs. During transient operations, the integrated master treats the turbine as a steam pressure regulator. On load increases the turbine is supplied a header pressure control setpoint lower than actual steam header pressure, and on load decreases the turbine is supplied with a setpoint that is higher than actual steam header pressure. This modification of setpoint is accomplished by comparing generator load with the megawatt demand from the ULD in the MW error difference unit (Δ) as shown in Figure 9-2. The difference between the two inputs is supplied to a summing amplifier where it is combined with the header pressure setpoint (SP), normally 1035 psia, supplied by the operator. This summing amplifier modifies the header pressure setpoint as previously described. The output of the summing unit is supplied as a setpoint to the pressure-error-(turbine) unit where a comparison with actual steam header pressure (PT) is made. The error that results from this comparison is supplied to the turbine electro-hydraulic control (EHC) system and is translated into a turbine control valve position demand. If the load change from 50% to 75% is examined in this portion of the integrated master, then the following actions are noted:

1. As the ULD megawatt demand is increased, an error between actual generated megawatts and megawatt demand is sensed by the Mw error difference unit (Δ).

2. The megawatt error signal is combined with the header pressure setpoint in the summing amplifier (∑). The output of this amplifier is a reduced header pressure setpoint.

3. The reduced header pressure setpoint is subtracted from actual header pressure in the pressure error (turbine) difference unit resulting in a pressure error signal.

4. The pressure error signal is supplied to the turbine. This error signal "informs" the turbine that actual steam pressure is higher than setpoint. With a high error signal, the turbine EHC system opens the turbine control valves in an effort to restore header pressure to normal.

5. As the turbine valves are opened, steam flow to the turbine increases. The increased steam flow causes an increase in generated megawatts.

Actions (1) through (5) will continue until the turbine generator is at 75% load. The actions on a load decrease signal are just the opposite. When the decreased megawatt demand signal from the ULD is sensed in the integrated master, the header pressure setpoint is increased. The turbine is informed that actual steam pressure is less than setpoint. The response of the turbine EHC system is to close the control valves in order to raise steam pressure. The closing of the turbine valves decreases steam flow, which, in turn, lowers turbine load.

Thus far the turbine's control of header pressure has been discussed only during fully automatic operations of the ICS, but the turbine also controls header pressure during tracking operations. When track is initiated, transfer relay T_2 in Figure 9-2 transfers in a zero modification. This transfer function prevents the modification, by megawatt error, of the header pressure setpoint during tracking operations (see Table 9-2). Since header pressure modification is blocked, the output of the summing amplifier (∑) is the operator-supplied header pressure setpoint. Any deviation between actual header pressure and setpoint is sensed in the pressure error (turbine) unit. The turbine valves respond to pressure error. They open if pressure is high and close if pressure is low. Changes in valve position cause changes in turbine load which are tracked by the ICS stations.

The response of the turbine valves to header pressure errors, as described above, occurs only if the turbine EHC system is in automatic. When the turbine EHC system is in manual, the operator must control header pressure.

9.2.2.2 Output Signal Modification

The second function of the integrated master is to provide a modified signal to the feedwater and reactor demand subassemblies. This signal modifier consists of a difference (pressure-error-(modifier)) unit (Δ) that is supplied with a header pressure input from actual steam pressure (PT) and a header pressure setpoint (SP). The output of this difference unit is header pressure error and is supplied to a summing amplifier (∑) located between the variable gain unit (χ) and the steam generator/reactor master hand/automatic station shown in Figure 9-2. The purpose of the signal modification circuit is to allow rapid achievement of the desired turbine load at the desired steam pressure during load increases or load decreases. On load increases, turbine load is quickly achieved by excess energy removal from the OTSG. This excess energy removal results in a decrease in steam header pressure, which, in turn, causes a header pressure error. The error is added to the megawatt demand signal, and appropriate increases in feedwater demand and reactor demand restore header pressure to normal. On decreases in turbine generation, the turbine again reaches the required setpoint before the feedwater system or the reactor. In this maneuver header pressure rises because the reactor's heat generation exceeds the turbine's heat removal. The rise in header pressure, when compared with the setpoint, results in an error, which, when added to the megawatt demand, decreases the feedwater and reactor demands, returning header pressure to setpoint.

9.2.2.3 Turbine Bypass and Atmospheric Dump Valve Control

The third function of the integrated master is the control of the steam dump and turbine bypass valves. There are 22 steam dump and turbine bypass valves divided into five groups: six modulating turbine bypass valves with a total capacity of 18.5%, four "off-on" bank 2 atmospheric dump valves with a capacity of 19.6%, four "off-on" bank 3 atmospheric dump valves with a capacity of 19.6%, four "off-on" bank 4 atmospheric dump valves with a capacity of 19.6%, and four "off-on" bank 5 atmospheric dump valves with a capacity of 19.6%. Control of these valves is accomplished by a header pressure error signal developed by comparing actual header pressure (PT) with the header pressure setpoint (SP) in the pressure-error-(valves) unit. The error signal from this comparison is supplied to each group of steam dump valves. Three different bias values may be added to the header pressure error signal. These bias values are represented by numbers located in boxes in Figure 9-2. The transfer relay (T_3, T_4, T_5, T_6 and T_7) directly below the bias boxes selects the correct value of bias that is to be subtracted from the header pressure error signal. The value of bias selected is dependent on specific plant conditions and is explained later. From the transfer relays, the error signals are passed through hand/automatic stations for the turbine bypass valves, or directly to the valves in the case of the other four groups. An interlock prevents opening the turbine bypass valves, which admit steam to the condenser, if the condenser is not in service. (See Table 9-2.) This interlock is represented by the box labeled "Cond Intlk" (condenser interlock) and transfer relays T_8 shown in Figure 9-2.

Now that the control devices for the valves have been described, the purpose of the different bias values will be explained in the following paragraphs. Three specific plant conditions determine the amount of bias subtracted from the header pressure error signal. (See Table 9-2.) These conditions are a turbine trip, normal power operations, or a reactor trip. When the turbine is tripped, a bias value of 0 psi is selected for the turbine bypass valves, a bias value of 15 psi is selected for the bank 2 atmospheric dump valves, a bias value of 30 psi is selected for the bank 3 atmospheric dump valves, a bias value of 45 psi is selected for the bank 4 atmospheric dump valves, and a bias value of 60 psi is selected for the bank 5 atmospheric dump valves. These particular values allow the control of steam pressure at its normal value during the following conditions:

1. turbine trip
2. plant startup - dissipates reactor coolant pump and reactor heat before turbine loading
3. maintains unit at 0% power T_{ave} before criticality

During normal operations, bias values of 50, 65, 85, 105, and 125 psi are selected for the turbine bypass valves, bank 2 atmospheric dump valves, bank 3 atmospheric dump valves, bank 4 atmospheric dump valves and bank 5 atmospheric dump valves, respectively. These biases are high enough to prevent valve actuation during minor perturbations yet low enough to prevent steam safety valve actuation during larger perturbations.

During the power escalation, these bias values are automatically selected when the turbine bypass valves close and steam header pressure error is less than 10 psi, or unit load demand is >15%.

When the reactor trips, bias values of 165, 175, 185, and 195 psi are selected for the turbine bypass valves, bank 2 atmospheric dump valves, bank 3 and bank 4 atmospheric dump valves, and bank 5 atmospheric dump valves, respectively. The high bias values are used after a reactor trip to minimize reactor coolant system (RCS) cooldown and the effect of this cooldown on pressurizer level and pressure. Normal pressurizer level is 220 in., and normal (>15% power) T_{ave} is 601°F. For every degree change in T_{ave}, pressurizer level changes by approximately 5 in. If a cooldown to no-load T_{ave} following a reactor trip occurs, then, by using the T_{ave}/pressurizer level relationship, pressurizer level would decrease below the indicated range.

601°F - 550°F = 51F°
51F° × 5in./F° = 255 in. (contraction)
220 in. - 255 in. = −35 in. pressurizer level

The reactor trip bias values allow a cooldown to 567°F, and the resulting pressurizer level is 50 in.

601°F - 567°F = 34F°
34F° × 5 in./F° = 170 in. (contraction)
220 in. - 170 in. = 50 in. pressure level

Figure 9-3 shows the effects of the different bias values. A discussion of the steam dump valve operation during plant heatup, reactor startup, and power escalation provides a convenient method of summarizing the bias value selection and valve operation. When the reactor coolant pumps are running, energy is being added to the reactor coolant. The energy addition raises reactor coolant temperature. As heat is transferred from the reactor coolant to the OTSGs, steam pressure increases. When the pressure-error-(valves) difference unit senses that actual steam pressure is equal to or greater than 1035 psia (the normal setpoint), then a positive error signal is transmitted to the bias boxes. Since the turbine is off-line, the turbine trip values will be selected. Looking at the turbine bypass valves, a value of zero will be subtracted from the error signal, and valve actuation will occur. As the error signal increases, the turbine bypass valves will open further. The actions of the turbine bypass valves control header pressure at setpoint. If the error signal should exceed 15 psi, then atmospheric bank 2 valves will open. Similar error values of 30, 45, and 60 psi will cause actuation of the bank 3, 4, and 5 atmospheric dump valves. The turbine bypass valves stabilize the unit at hot standby (operating mode 3) and dissipate the reactor coolant pump heat and the reactor's decay heat.

The reactor is now brought to a critical condition, and power is escalated to approximately 15%. The reactor's heat is dumped to the condenser by the turbine bypass valves. At 15%, the turbine is placed in service. As the turbine starts to assume electrical load from the grid, header pressure tends to decrease. To prevent the decrease in header pressure, the turbine bypass valves close. When the valves are fully closed and header pressure error is less than 10 psi, then the "normal" values of bias will be selected. Power escalation from 15% to 100% is achieved with the turbine controlling steam pressure and the steam dump and turbine bypass valves acting as relief valves. If the reactor trips, the reactor trip bias values will be selected. The response of header pressure when the reactor trips is shown in Figure 9-4.

9.2.2.4 Plant Efficiency Compensation

The next function of the integrated master is compensation for changes in plant efficiency to maintain a constant plant load. In Figure 9-2 an integrator senses the megawatt error (the difference between megawatt demand and actual generated megawatts) and sends this signal, via the dashed lines, to the variable gain unit (χ) and the summing amplifier (∑). This portion of the integrated master is called the calibrating integral. The operation of this calibrating integral can be illustrated by assuming an increase in circulating water temperature. With an increase in circulating water temperature, vacuum decreases. In turn, when vacuum decreases, turbine efficiency decreases. A decrease in turbine efficiency causes a decrease in generated megawatts. When megawatts drop, a megawatt error is developed. This error is integrated and applied to both the variable gain unit and summing amplifier. The megawatt demand signal from the ULD is increased to the reactor and feedwater demands by these two units. The turbine load will be returned to setpoint by the megawatt error described earlier in this section. At low loads the change in gain required to compensate for small megawatt errors is large; therefore, the output of the calibrating integral is supplied to the summing amplifier. Megawatt errors at high loads can be compensated for by small changes in gain; therefore, the calibrating integral's output to the variable gain unit is sufficient to cause the required change in the megawatt demand signal. The megawatt demand, after being modified by either the header pressure error or the calibrating integral, is transmitted to a hand/automatic station. This hand/automatic station is called the steam generator/reactor master and gives the operator control of the demand signal being sent to the reactor and feedwater demand subassemblies. Placing the steam generator/reactor master in hand initiates track and also prevents runback signals from reaching the reactor and feedwater demand subassemblies.

9.2.2.5 Integrated Master Output

The final function of the integrated master is to characterize the megawatt demand into demand signals for the feedwater and reactor demand subassemblies. This function is accomplished by multiplying the megawatt demand signal by proportionality constants yielding demands for the feedwater system and the reactor. This characterization is represented in Figure 9-2 by the boxes labeled "Feedwater Demand Calculator" and "Reactor Demand Calculator." A low limiter, set at 15%, limits the demand signal to the reactor.

9.2.3 Feedwater Demand Subassembly

It would seem that feedwater flow could be controlled by comparing the feedwater demand with actual feedwater flow and modulating the feedwater regulating valves and feed pump turbine speed to achieve the desired amount of feedwater flow. Indeed, this is done, but the design of the OTSGs and the RCS prevents the use of a simple control system. Before the limitations placed on feedwater demand are discussed, the basic control loops will be described. The feedwater demand, after being characterized by the integrated master, is supplied from the unit load demand subassembly. The feedwater demand signal is represented in Figure 9-2 by a line from the feedwater demand calculator to the variable gain unit (χ). From the variable gain unit (χ), the signal passes through a summing amplifier (∑) and then splits into two paths. These two paths eventually become the demand signals for the feedwater supply to the A and B OTSGs. The demand signal for the A OTSG is through a variable gain unit (χ), a hand/automatic station, a difference unit, and a transfer relay. The difference unit calculates the error between actual feedwater flow, supplied by the loop A feedwater flow transmitter (FT), and feedwater demand. The error signal travels from the difference unit (Δ) to a high-select unit (>), and through the individual valve hand/automatic stations to the feedwater regulating valves for the A OTSG. The signal path for the B OSTG feedwater control is identical, except that a difference unit (Δ) is used upstream of the loop demand hand/automatic station. The signal to the feedwater regulating valves is an error signal based on the difference between loop B feedwater demand and actual loop B feedwater flow. As previously stated, the control of feedwater flow is complicated by design considerations of the OTSG and RCS. Considerations such as feedwater temperature, RCS average temperature, the difference between the RCS loop cold-leg temperatures, and the difference between reactor power demand and actual reactor power add signal modifications to the feedwater demand.

9.2.3.1 Signal Modification

Modifications to the feedwater demand signal are described below:

Average Feedwater Temperature

The first modification to the feedwater demand signal is made by average feedwater temperature. At any given load value, there is a balance of Btu exchange between the primary and secondary sides of the OTSGs. To not disturb this ratio, when feedwater temperature varies, the total feedwater demand is modified by a function of feedwater temperature. With a fixed RCS temperature and a fixed ΔT across the primary side of each OTSG, a fixed amount of energy is available. If colder feedwater is introduced into the secondary side of a steam generator at a fixed flow rate, more heat would be required to raise this fluid to the proper steam generator outlet conditions, i.e., superheated to the proper value. However, if the flow rate on the secondary side were reduced, the total amount of energy required to raise the colder feedwater to the proper outlet conditions would also be reduced. Therefore, by properly reducing the feedwater flow rate for a given feedwater temperature reduction, the proper OTSG steam conditions can be maintained.

A comparison between actual feedwater temperature and the desired feedwater temperature versus power is made. If feedwater temperature is lower than the desired temperature, a reduction in feedwater demand will occur. A graph of the desired feedwater temperature versus power is shown in Figure 9-5. The minimum feedwater temperature is maintained by the main steam supply to the high-pressure heaters. If feedwater loop temperature decreases to 340°F, an automatic trip of the main feedwater pump associated with that loop is initiated. In Figure 9-2, the output of the feedwater temperature limit is supplied to a variable gain amplifier (χ). If the average temperature is greater than the desired temperature, the gain of the amplifier is unity. If the average temperature is less than the desired temperature, the gain of the amplifier is proportionally reduced. Reducing feedwater demand decreases feedwater flow. The output of the variable gain unit is supplied to the feedwater demand summer ($\sum$).

Average Reactor Coolant Temperature

In the feedwater demand summing amplifier ($\sum$), the second feedwater demand modification occurs. This modification of the feedwater demand allows feedwater flow to control average RCS temperature. A summing amplifier input of T_{ave} error supplied by the reactor demand subassembly is shown in Figure 9-2. Because the heat transfer characteristics of the OTSGs are not fixed, as they are in the U-tube steam generator design, the control of T_{ave} can be accomplished by varying the sizes of the heat transfer regions in the OTSGs. If T_{ave} increases, then an increase in the subcooled liquid and nucleate boiling heat transfer areas (OTSG levels) will restore the parameter. Conversely, a low T_{ave} can be returned to normal by a decrease in the subcooled liquid and nucleate boiling heat transfer areas. The amount of heat transfer area available in the subcooled liquid and nucleate boiling regions of the OTSGs is a function of feedwater supply; therefore, a high T_{ave} error requires an increase in feedwater flow, and a low T_{ave} error requires a decrease in feedwater flow. The required increases or decreases in feedwater flow are accomplished by feedwater demand additions or subtractions in the feedwater demand summing amplifier. The summing amplifier will receive the T_{ave} error input if the reactor demand is not capable of controlling temperature and feedwater is capable of accepting temperature control. The reactor demand is not capable of T_{ave} control if the reactor demand hand/automatic station is in hand or the rod control (Diamond) station is in manual. The feedwater demand subassembly will accept T_{ave} control if at least one steam generator is not on low-level limits and at least one feedwater demand station is in automatic. (See Table 9-2.) Low-level limits are discussed later in this section.

Reactor Cross Limits

The third modification to the feedwater demand signal is also made in the summing amplifier. This modification is called reactor cross limits. It is very desirable to maintain heat generation (reactor power) equal to heat removal (feedwater flow). If a large difference between reactor demand and reactor power exists, then feedwater demand must be modified. A large difference is defined as any difference in excess of 5% and is determined in the reactor demand subassembly. The modification of feedwater demand by reactor cross limits is shown in the following formula:

$$|\text{Rx demand} - \text{Rx power}| - 5\% = \text{FW demand modification (positive values only)}$$

Assume that reactor demand is 50% (since the ICS is in automatic, feedwater demand is also 50%) and reactor power is 44%. In this example an error of 6%, as sensed by the comparison of reactor demand and reactor power, exists. The 6% error exceeds the allowable error of 5%; therefore, the signal sent to the feedwater demand summer will reduce feedwater demand by 1%. If a reactor demand of 50% and a reactor power of 58% are assumed, then the reactor cross limits signal that is sent to the feedwater demand summer will increase feedwater demand by 3%.

When reactor cross limits occur, feedwater demand is increased or decreased, and the ICS is placed in track. In track, actual generated megawatts become the demand signal for the remainder of the ICS, and the load transient will stop. Cross limits act to maintain the proper relationship between heat generation (reactor demand) and heat removal (feedwater demand).

After the modifications of feedwater temperature, RCS average temperature, and reactor cross limits are made, the feedwater demand signal is finally sent to the loop A and loop B feedwater demand strings.

9.2.3.2 Loop Feedwater Demand

The loop feedwater demand strings are shown in Figure 9-2. On the A side the total feedwater demand signal is routed through a variable gain amplifier (χ). The feedwater demand for the A OTSG is calculated here and is equal to the total feedwater demand times the gain of the variable gain amplifier. If the total demand is 100% and the gain of the amplifier is 0.5 (its normal value), then the feedwater demand for the A OTSG is equal to 50%. On the B side the feedwater demand for the B OTSG is calculated by a difference unit (Δ). The inputs to the difference unit are total feedwater demand and loop A feedwater demand; therefore, the loop B feedwater demand equals the total feedwater demand minus the loop A feedwater demand. Using the example above, total feedwater demand minus loop A feedwater demand (100% - 50%) equals a 50% demand for the B OTSG. These values are the normal 100% power conditions; however, if an asymmetric RCS flow condition or a difference between the cold leg temperatures is present, the feedwater demands to the OTSGs will change.

9.2.3.3 Asymmetric Reactor Coolant System Flow

Asymmetric flow conditions are sensed in the ICS by RCS flow transmitter inputs. RCS loop B flow is subtracted from RCS loop A flow in a difference unit (Δ), and the result is transmitted to a summing amplifier (∑). The RCS flow is combined with any difference between the RCS cold-leg temperatures (ΔT_c) in the summing amplifier. The output of the summing amplifier determines the gain of the variable gain amplifier (χ) that is used in the loop A feedwater demand calculations. If two reactor coolant (RC) pumps are operating in the A reactor coolant loop and one RC pump is operating in the B reactor coolant loop, then the ICS will limit megawatt production to 75%. Since only one RC pump is operating in loop B, the energy available in the B OTSG is limited. The energy removal (feedwater flow) from the B OTSG must also be limited, and this is accomplished in the following manner:

1. The RC flow difference alters the gain of the loop A feedwater demand variable gain unit from 0.5 to 0.66.

2. The feedwater demand to the A OTSG equals total feedwater demand times gain, that is, 75% x 0.66 = 49.5%.

3. The feedwater demand for the B OTSG equals the total feedwater demand minus loop A feedwater demand, that is, 75% - 49.5% = 25.5%.

4. Feedwater demands to the OTSGs are proportional to the energy available to each steam generator.

It should be noted that the subcooled liquid and nucleate boiling heat transfer areas (level) in the A OTSG will be greater than those in the B OTSG because of the difference in feedwater supply rates. If the action of the RC flow circuit does not equalize the RCS cold-leg temperatures, then the ΔT_c circuit acting through the summing amplifier will add the necessary corrections.

9.2.3.4 ΔT_c Compensation

The ΔT_c circuit consists of an input of the difference between loop A and loop B inlet temperatures (ΔT_c) and an operator-supplied setpoint (usually 0). The setpoint is compared with the ΔT_c input, and the result is supplied to the summing amplifier through a hand/automatic station. ΔT_c control is designed to equalize loop cold-leg temperatures to prevent unequal radial flux distributions in the core. The radial flux imbalance would result because of the lack of perfect mixing of vessel inlet temperatures. Operational situations that could result in ΔT_c conditions are unequal fouling of the steam generators, plugging of tubes in one steam generator, and, of course, asymmetric RCS flow conditions. The gain of the variable gain amplifier in the loop A feedwater demand is altered by ΔT_c corrections.

9.2.3.5 Feedwater Hand/Automatic Control

Stations

The feedwater demand signal, after being modified by RCS flow and/or ΔT_c, is passed to the loop feedwater demand hand/automatic stations. These stations allow the operator to select manual control of the feedwater demands to the A and B OTSGs. If manual control is selected, the feedwater temperature, reactor cross limits, RCS flow and ΔT_c modifications are blocked. Manual control of both of these stations places the ICS in track.

9.2.3.6 Flow Error Derivation

Whether the station is in hand or automatic, its output is sent to a difference amplifier in the associated loop feedwater demand string. In the difference unit the error between feedwater demand and actual feedwater flow is calculated. This error signal will eventually control feedwater valve position.

9.2.3.7 BTU Limits

The BTU limits help to ensure that the steam from each OTSG never reaches saturated conditions. This is necessary because no moisture separation equipment is installed in the steam generator. Steam leaving the OTSG with a high moisture content would be detrimental to the high-pressure turbine. The inputs into the BTU limits calculation are the reactor outlet temperature (T_h), reactor coolant flow, feedwater temperature, and OTSG pressure. The first two inputs (T_h and RC flow) are used as a measure of heat input to the OTSG, and the other two (OTSG pressure and feedwater temperature) are a measure of the heat removed from the OTSG. If BTU limits are reached, an alarm is sounded in the control room. The operator should take manual actions to ensure that the OTSGs do not operate in a saturated steam condition. Figure 9-9 shows the effect of BTU limits on the alarm setpoint calculation.

In the original design of the ICS, BTU limits reduced feedwater demand. However, with this ICS configuration, certain instrument failures can cause a reduction in feedwater (because of BTU limits) and an increase in reactor power. This large upset in heat transfer results in undesired pressure excursions in the RCS. Consequently, the BTU limits signal was removed from the ICS in the late 1980s.

9.2.3.8 Feedwater Control Following a Reactor Trip

From the output of the feedwater flow error amplifier in each loop demand string, the feedwater demand signal is sent to a transfer relay (T_{10}, T_{11}). This transfer relay transfers the level error signal to the feedwater valves after a reactor trip. The purpose of the signal transfer is to prevent overcooling the RCS with the addition of large amounts of feedwater following a reactor trip. Immediately following the trip, steam generator levels are above the low-level limit setpoint; therefore, the large negative level error signal will shut the feedwater valves. (See Table 9-2.) After passing through the transfer relay, the feedwater demand signal is sent to a high-select unit (>).

9.2.3.9 Level Error

The high-select device (>) is used to select either feedwater flow error or steam generator level error for the control of the feedwater valves. Level error is derived from the comparison between level setpoint and the selected startup range level input. Between 0% and 15% power OTSG level is maintained at the low-level limit (2 ft); as reactor power is increased, T_{ave} escalates from its no load value to its 15% load value.

From 15% to 100% the level in the OTSG is increased and T_{ave} is held constant. The switchover from low-level limit to flow error control occurs automatically in the high-select (>) device when the magnitude of feedwater flow error exceeds the magnitude of level error. A 6-ft level setpoint is provided to increase generator level if all four reactor coolant pumps are lost. The increase in the subcooled liquid and nucleate boiling heat transfer areas promotes natural circulation in the OTSG. A transfer relay (T_{12}, T_{13}) will select the 6-ft setpoint if all four pumps are lost. (See Table 9-2.)

9.2.3.10 Feedwater Control Valve Operation

The output of the high-select device is sent to the feedwater control valves. Two feedwater control valves are installed in each OTSG feedwater supply line. These valves are the startup feedwater regulating valve, which is used to control feedwater flow between 0% and 15% power, and the main feedwater regulating valve, which controls feedwater flow between 15% and 100% power. The valves are sequenced into service by the ICS. The sequence program for these valves is shown in Figure 9-6. In addition to sequencing the feedwater valves, the ICS opens a block valve in series with the main feedwater regulating valve when the startup regulating valve is 80% open. A differential pressure transmitter piped across the feedwater regulating valves is used in the feedwater pump turbine speed control circuit.

9.2.3.11 Feedwater Pump Turbine Speed Control

The feedwater pump turbine speed is controlled to maintain a constant differential pressure across the feedwater regulating valves. A low-select device (<) selects the lowest of the valve differential pressure (ΔP) inputs and compares this value with a setpoint (SP) in a difference unit (Δ). The ΔP error signal is sent to a summing amplifier ($\sum$). The summing amplifier adds the total feedwater demand signal to the ΔP error. The total feedwater demand signal is developed by adding the loop A and loop B demand signals in a summing unit. The addition of the total feedwater demand signal to the ΔP error signal provides an anticipatory speed demand for the turbines on rapid load changes. Otherwise, feedwater pump turbine speed is a function of valve differential pressure. As the feedwater regulating valves are opened up by the feedwater flow error signal, the ΔP across each valve tends to drop. When the valve ΔP drops, the feedwater pump turbine speed is increased to restore the valve ΔP to setpoint.

9.2.3.12 Subassembly Operations

Examining the actions of the feedwater demand subassembly during a plant startup provides a method of illustrating integrated system operations. The OTSGs are on low-level limits in the first phases of the startup. The low-level limit is maintained by the level error signal created by the difference between startup range level and the level setpoint of 2 ft. The level error signal modulates the startup feedwater regulating valve to maintain level. As heat from the reactor is added to the OTSG, its boiling rate increases, and a greater opening of the startup feedwater regulating valve is required to maintain correct OTSG level. At approximately 15% power, the feedwater flow error signal exceeds the level error signal and is used as the controlling signal. The inventory in the OTSG is controlled by feedwater flow through both the startup feedwater regulating valve and the main feedwater regulating valve. Above 15% the startup valve remains 100% open, and the main feedwater regulating valve is modulated. Valve position changes cause ΔP

changes that result in speed changes of the main feedwater pump turbines. These actions continue until the unit is at 100% power.

If a reactor trip occurs from 100%, then the level error is selected as the control signal input to the loop feedwater flow control valves. The level setpoint is compared immediately with a large level signal, and the resultant large level error closes the feedwater regulating valves. When the feedwater regulating valves close, the large ΔP error, combined with the large change in flow demand, rapidly reduces feedwater pump turbine speed to its minimum value. The combination of reduced feedwater flow and steam flow through the steam dump valves reduces the OTSG inventory. As inventory drops below the low-level limit setpoint, the high-select device allows OTSG level error to control feedwater flow.

In this section, the characterized megawatt demand signal has been converted to a feedwater demand signal. The next section discusses the megawatt demand signal sent to the reactor demand subassembly.

9.2.4 Reactor Demand Subassembly

The megawatt demand signal from the unit load demand is converted to a reactor demand signal in the integrated master subassembly. When the megawatt demand signal exceeds 15%, it is sent to the reactor demand subassembly. In the reactor demand subassembly (Figure 9-2), the megawatt demand signal is combined with three other signals in a summing amplifier ($\sum$). These signals are T_{ave} error, T_{ave} calibrating integral input, and feedwater cross limits.

9.2.4.1 T_{ave} Input

The T_{ave} error is developed by comparing an actual T_{ave} signal with a setpoint (normally 601°F) in a difference unit (Δ). If T_{ave} is below setpoint, the reactor demand signal will be increased. If T_{ave} is above setpoint, then reactor demand will be reduced. The T_{ave} error is also sent to a calibrating integral. The calibrating integral supplies outputs to the reactor demand summing amplifier and to a variable gain unit (χ). The variable gain unit is used to adjust for T_{ave} errors at high demands, when a small change in gain causes a large change in output. The calibrating integral output to the summing amplifier allows adjustment for T_{ave} errors at low-demand conditions. The output of the T_{ave} calibrating integral is blocked if the demand signal is changing more quickly than 2% per minute, if T_{ave} is below setpoint with the OTSGs on low-level limits, or if the reactor demand hand/ automatic station is in manual.

9.2.4.2 Feedwater Cross Limits

The third input into the summing amplifier is feedwater cross limits. The feedwater cross limits function to reduce reactor demand when feedwater flow is less than feedwater demand by more than 5%. The reduction in reactor demand is necessary to keep heat generation (reactor power) within the limits of the heat removal (feedwater) system. The signal for the reduction of reactor demand is calculated in the feedwater demand subassembly as the difference between feedwater demand and actual feedwater flow. Assigning numbers to these signals will explain the actions of feedwater cross limits. If the feedwater demand signal is 80% and actual feedwater flow is 74%, the feedwater cross limits signal will reduce reactor demand by 1%. Values of feedwater cross limit signals may be calculated by the following formula:

(FW demand - FW flow) - 5% = reduction in reactor demand signal

Feedwater cross limits can only reduce reactor demand. Feedwater cross limits result in TRACK.

After the summing unit combines reactor demand with cross limits and the T_{ave} errors, the signal is routed to the variable gain unit (χ), where the demand signal is adjusted by the T_{ave} calibrating integral. From the variable gain unit (χ), the signal is directed to the Hi-102%, Lo-10% limits box shown in Figure 9-2. The purpose of the Hi/Lo limits is to allow T_{ave} errors to increase the reactor demand to greater than 100% and decrease demand to less than 15%. A word of caution: The 102% limit is a limit on reactor demand, not reactor power. High reactor power trips can occur even though the demand signal is at the high limit. If the reactor demand signal is within limits, it is passed to the reactor demand hand/automatic station.

9.2.4.3 Reactor Demand Station

The reactor demand hand/automatic station allows manual control of reactor power by the operator. If this station is placed in hand, the ICS will go into TRACK. Several interlocks must be satisfied to place the reactor demand station in automatic:

1. Power must be available to the ICS.
2. The DIAMOND rod control station must be in automatic.
3. The difference between reactor power and reactor demand must be less than 1%.

The output from the reactor demand hand/automatic station is supplied to a difference unit (Δ). In the difference unit, actual reactor power is compared with reactor demand, and the resultant error (called neutron error) will cause rod motion. To prevent continuous rod motion, the neutron error must exceed a predetermined deadband before rod motion will be initiated. The deadband is illustrated in Figure 9-7. From the difference unit the neutron error signal is routed through the Diamond rod control station to the control rod drive control system. Three non-ICS outputs are supplied by the nuclear instrumentation input to the reactor demand subassembly: a neutron power signal to the boration control system, an RC pump start interlock, and a control rod interlock to prevent rod withdrawal during asymmetric rod conditions. A block diagram of these outputs appears in Figure 9-8.

Again, operational activities can be used to summarize the actions of the reactor demand subassembly. Assume a power escalation from 60% to 80% is desired. The load change is initiated in the ULD subassembly by increasing the load setpoint. The rate limited megawatt demand signal passes from the ULD to the integrated master where it is characterized for the reactor demand subassembly. The reactor demand signal is sent through the summing amplifier ($\sum$), the variable gain unit (χ), the HI/LO limits box, and finally to the difference unit (Δ). When the comparison between reactor demand and actual reactor power yields a difference greater than 1%, rod withdrawal will occur. When the rod withdrawal increases reactor power and the neutron error is reduced to less than 0.25%, then the rod withdrawal will stop. These actions continue until load is stabilized at 80%. If it is assumed that the main feedwater valve response is sluggish during the power escalation to 80%, feedwater cross limits can affect the reactor demand signal. The moment that the feedwater demand signal exceeds the actual feedwater flow value by 5%, feedwater cross limits are transmitted to the reactor demand subassembly. The cross limits reduce reactor power demand and place the ICS in TRACK. In track the reactor demand signal is set equal to the generated megawatts and is further reduced by feedwater cross limits. The unit operator can reinitiate the power escalation by changing the ULD setpoint when cross limits are cleared. The power escalation from 60% to 80% will cause changes in the xenon concentration in the core.

Initially, the concentration is reduced by the higher neutron flux level at 80%. When the concentration is decreased, positive reactivity is added to the reactor. This reactivity addition eventually results in an increase in T_{ave}. The elevated T_{ave} is sensed, and the T_{ave} error signal reduces the reactor demand signal, causing inward rod motion. The opposite effects occur if the xenon concentration is increased.

Now that each subassembly has been described, the next section of this chapter will deal with the overall operation of the integrated control system.

9.3 Integrated Operations

The events in the ICS occur simultaneously, and it is impossible to write concurrent descriptions of subassembly actions; therefore, the discussion of a particular transient will start with unit load demand (ULD) actions and continue through the integrated master, feedwater demand, and reactor demand actions.

9.3.1 Normal Power Increase

Initial Conditions: The plant is at a stable power level of 30% with all ICS hand/automatic stations in automatic. A load increase to 80% at a rate of 5% per minute is desired.

1. ULD Actions

   a. The operator must input the desired rate of load change and the new load value.

   b. In Figure 9-2, the new load value (at the desired rate of increase) is supplied to the frequency-correction summing amplifier (∑). At the end of 1 min, the output from the summing amplifier (ignoring any frequency correction) will have increased from 30% to35%.

   c. Since load is changing more quickly than 2% per minute, a signal is sent to block the outputs of the megawatt error and T_{ave} error calibrating integrals.

   d. Any required frequency correction is added to the megawatt demand signal in the frequency-correction summing amplifier.

From the ULD, the megawatt demand signal is sent to the integrated master.

2. Integrated Master Actions

   a. The megawatt demand signal is compared with generated megawatts, and the resultant megawatt error signal is sent to a summing amplifier (∑).

   b. In the summing amplifier, the megawatt error modifies the steam header pressure setpoint to a lower value.

   c. The reduced steam header pressure setpoint is combined with actual steam pressure in the pressure-error-(turbine) difference unit (Δ), and the error signal causes the turbine valves to open to lower header pressure back to setpoint.

   d. In reality, the opening of the turbine valves lowers steam pressure. The decreased steam pressure is compared with an unmodified header pressure setpoint in the pressure-error-(modifier) difference unit. The resulting error signal is added to the megawatt demand in the main integrated master summing amplifier. The pressure-error-(modifier) signal increases the megawatt demand signal being sent to the feedwater and reactor demand subassemblies.

The megawatt demand signal is translated to the proper signals for feedwater and the reactor in the integrated master, and the signal travels to the respective subassemblies.

3. Feedwater Demand Actions

   a. Since modifications from feedwater temperature, reactor cross limits, or T_{ave} error are not required, the feedwater demand signal is directed from the main summing amplifier ($\sum$) to the variable gain unit (χ) in the loop A feedwater demand and to the difference unit (Δ) in the loop B feedwater demand.

   b. Feedwater demand is compared with actual loop feedwater flows, and the resultant error signal increases the positions of the main feedwater regulating valves.

   c. The opening of the feedwater regulating valves decreases the valve ΔPs, and this signal, coupled with the increase in feedwater demand, increases main feedwater pump speed.

4. Reactor Demand Actions

   a. It will be assumed that the need for feedwater cross limits is not present; therefore, the reactor demand summing unit will receive signals from T_{ave} error and megawatt demand.

   b. Because the reactor demand is less than 102% and greater than 10%, the signal will pass through the Hi/Lo limits box directly to the difference unit (Δ).

   c. The comparison between reactor demand and reactor power creates a neutron error. The neutron error results in outward regulating rod motion.

The actions described above will continue until the unit load is at 80%. It should be noted that the pressure-error-(modifier) different unit (Δ) will continue with increases in feedwater and reactor demands until steam pressure is returned to normal.

9.3.2 Loss of One Reactor Coolant Pump

Initial conditions: Unit load is at 90% power. Group 7 control rods are 90% withdrawn.

1. ULD Actions

   a. When the reactor coolant pump is lost, a runback signal is initiated.

   b. A load reduction at the rate of 50% per minute is set into motion.

2. Integrated Master Actions

   a. The rapidly decreasing megawatt demand signal closes the turbine valves by modifying the steam header pressure setpoint to a value higher than the actual header pressure.

   b. The closing of the turbine valves increases actual steam pressure. If steam pressure exceeds its setpoint by 50 psi, the turbine bypass valves will open to relieve excess energy.

c. The demand to feedwater and the reactor will be further reduced by the pressure-error-(modifier) difference unit (Δ) signal.

3. Reactor Demand Actions

a. The reduced demand signal from the integrated master will cause inward regulating rod motion. T_{ave} error also will decrease this demand signal.

b. Because the regulating rods are almost fully withdrawn, a large amount of rod motion occurs with little change in reactor power. This will send reactor cross limits to feedwater.

Cross limits cause a tracking condition. Since the runback limits are inserted downstream of transfer relay T_1, the runback signal from the ULD is not affected. However, the tracking condition causes transfer relay T_2 to bleed the pressure setpoint modification signal to zero over a 100-sec time constant. If cross limits persist, then the reduction of turbine load will be accomplished by the pressure error that results from the decrease in reactor power and feedwater flow.

4. Feedwater Demand Actions

a. The reactor cross limits will limit the decrease in feedwater demand.

b. The actions of the RC flow and ΔT_c circuits will proportion feedwater between the OTSGs.

The actions listed above will continue until the load is stabilized at 75%.

9.3.3 Load Rejection

Initial conditions: Unit load is at 100% power. Group 7 rods are 90% withdrawn.

1. ULD Actions

When the main generator output breaker is opened, the ULD goes into TRACK. Generator load will be reduced to 0 MWe because of the configuration of the offsite power supply to the station transformers. This reduction in megawatt load becomes the new megawatt demand, and the ICS will track this reduction at 20% per minute. Also, the large reduction in turbine load will cause actuation of the overspeed protection control circuit, which will revert the control of the EHC system to manual, generating a second track condition.

2. Integrated Master Actions

a. Because the EHC is in manual, the integrated master cannot control the turbine. However, the closing of the turbine valves by the acceleration limiter (in its effort to prevent turbine overspeed) results in a large increase in steam header pressure.

b. A large header pressure error will be developed in the pressure-error-(valves) unit and cause actuation of the turbine bypass valves and atmospheric dump valves. The opening of these valves removes the excess energy from the RCS.

c. When the ULD demand drops below 15%, the turbine trip bias values will be selected, and header pressure will be controlled at 1035 psia.

3. Feedwater Demand Actions

   a. Feedwater flow will respond to the 20% per minute reduction in feedwater demand caused by the tracking condition. The reduction in feedwater flow will be tempered by cross limits from the reactor demand subassembly.

   b. The reduction in feedwater demand is the controlling signal until low-level limits become the controlling signal.

4. Reactor Demand Actions

   a. The reduction in the reactor demand causes insertion of the regulating rods. Due to the low rod worth at the upper end of group 7, the actual decrease in reactor power will not keep up with the decrease in reactor demand. This will result in cross limits in the feedwater demand subassembly.

   b. The reduction in reactor power continues until the reactor demand signal reaches 15%. After this occurs, the low-load limit will maintain reactor demand at 15%.

5. Final Conditions

   a. Reactor power is being maintained at 15%.

   b. Turbine bypass valves are dissipating the reactor's energy to the condenser while controlling header pressure at 1035 psia.

   c. OTSGs are on low-level limits (~2 ft. on startup range).

9.3.4 Reactor Trip

When the reactor trips, the turbine is also tripped. Therefore, the reactor demand subassembly cannot control the regulating rods and the integrated master cannot control the turbine.

1. ULD Actions

   The ULD is in TRACK and is reducing the megawatt demand signal to zero at a rate of 20% per minute.

2. Integrated Master Actions

   The reactor trip biases are chosen for the control of header pressure by all five valve groups. As the energy of the RCS is removed by the turbine bypass valves and atmospheric dump valves, the pressure error will decrease. At the end of the transient, header pressure will be 1200 psia, with the excess energy being dissipated to the condenser by the turbine bypass valves.

3. Feedwater Demand Actions

   a. When the reactor trip signal is received, the level error signal is transferred to the feedwater regulating valves by transfer relays T_{10} and T_{11}, causing a rapid reduction in feedwater flow.

   b. When the OTSGs reach the low-level limit, the feedwater regulating valves will be modulated to control at this setpoint.

4. Final Conditions

   a. Turbine bypass valves are dissipating reactor decay heat and reactor coolant pump heat to the condenser by controlling header pressure at 1200 psia (T_{ave} ~

567°F).

b. Once-through steam generators are at their low-level limit.

9.3.5 Turbine EHC in Manual

Initial conditions: The unit is at 50% load, and the EHC is placed in operator auto control. The operator initiates a load decrease to 40% by changing the load setpoint.

1. ULD Actions

a. When the operator auto mode of control is selected, the ICS goes into TRACK. Actual generated Mwe becomes the unit load demand, which is transferred to the feedwater and reactor demand subassemblies.

b. As turbine load is reduced, the demand to the feedwater and reactor demand subassemblies will also be reduced.

2. Integrated Master Actions

a. Since the turbine is being controlled by the EHC system, the signal from the ICS is not sensed by the turbine.

b. Should header pressure exceed the 1035 psia setpoint plus the "normal" bias values, turbine bypass valves and/or atmospheric dump valves will open.

3. Feedwater Demand Actions

a. As the demand signal from the ULD decreases, the feedwater demand signal decreases.

b. Feedwater flow is reduced as the regulating valve positions and feed pump speeds are reduced by the decreased feedwater demand signal. Feedwater flow will equal 40% at the end of the transient.

4. Reactor Demand Actions

a. As reactor demand is decreased, reactor power will be reduced by regulating rod insertion.

b. Reactor power will stabilize at 40% at the end of the transient.

9.3.6 Seam Generator/Reactor Master in Manual

Initial Conditions: The unit is at 75% power, and the operator places the Steam Generator/Reactor Master in manual and increases its output to a demanded value of 80%.

1. Feedwater and Reactor Demand Actions

a. As the output of the steam generator-reactor master is increased, feedwater flow and reactor power increase in response to the increase in their demands.

b. The increased energy is deposited into the OTSGs, and header pressure goes up.

2. Integrated Master Actions

Since the unit is in TRACK, the turbine receives an unmodified header pressure setpoint. As header pressure is increased by the reactor and feedwater demand subassemblies, the turbine control valves open to return header pressure to the 1035 psia setpoint. As the turbine control valves open, load will increase to 80%.

3. ULD Actions

   Due to the tracking condition, the output of the ULD follows generated Mwe. This increase in ULD does nothing in this particular transient because (1) relay T_2 prevents the modification of header pressure setpoint to the turbine, and (2) the steam generator-reactor master is in manual and prevents the ULD signal from reaching the feedwater and reactor demands. However, the input to the steam generator-reactor master is increased as the ULD's output is increased and should help make the transfer back to automatic bumpless.

9.3.7 Both Feedwater Demand Hand/Automatic Stations in Manual

Initial Conditions: The unit is at 50% power, and the operator places both feedwater demand stations in manual. Both stations in manual causes the ICS to go into TRACK. After taking manual control, the operator increases loop A and loop B feedwater demands to 80%.

1. Feedwater Demand Actions

   With an increase in feedwater demand, feedwater flow is increased by the action of the feedwater regulating valves and the increase in main feed pump speed. This increase in feedwater flow results in an increase in energy transfer in the economizer and nucleate boiling sections of the OTSGs. This increase in heat transfer, combined with a turbine load of 50%, increases header pressure.

2. Integrated Master Actions

   a. With an increase in header pressure, the turbine valves open to restore header pressure to 1035 psia (unmodified setpoint due to TRACK).

   b. As the turbine valves open, generated megawatts (Mwe) increase to 80%.

3. ULD Actions

   As generated megawatts (Mwe) increase, the output of the ULD increases.

4. Reactor Demand Actions

   a. As the output of the ULD increases the reactor demand signal, regulating rods are withdrawn to increase reactor power to 80%.

   b. If the increase in feed flow causes a decrease in T_{ave}, the T_{ave} error will be added to the reactor demand signal to restore T_{ave} to 601°F.

9.3.8 Reactor Demand Hand/Automatic Station to Manual

Initial Conditions: The unit is at 100% power, and the operator places the reactor demand hand/automatic station to hand and decreases its output to 90%. Placing the station in hand causes TRACK and also transfers T_{ave} control to the feedwater demand subassembly.

1. Reactor Demand Actions

   As the regulating rods insert due to a decrease in the reactor demand setpoint, reactor power decreases. With less energy being deposited into the OTSGs, header pressure decreases.

2. Integrated Master Actions

   a. The turbine control valves close to restore header pressure to 1035 psia.

b. As the control valves close, turbine load decreases to 90%.

3. ULD Actions

The output of the ULD tracks the decrease in turbine load and corresponding decrease in MWe.

4. Feedwater Demand Actions

a. Feedwater flow decreases to 90% following the decrease in the ULD's output.

b. If a T_{ave} error exists, feedwater demand will be altered to return T_{ave} to 601°F.

TABLE 9-1 RUNBACK CONDITIONS

Condition	Runback Rate	Maximum Load Value
Loss of an RCP	50%/minute	75% generated Mw
Loss of 2 RCPs	50%/minute	50% generated Mw
Loss of a MFP	50%/minute	60% generated Mw
Asymmetric Rod	30%/minute	60% generated Mw
RCS Flow	20%/minute	Value required to maintain correct power/flow ratio

TABLE 9-2 TRANSFER RELAY LOGIC

1. Unit load demand tracking relay - T_1

a. Normal condition - passes the megawatt demand signal from the Unit Load Demand hand/automatic station to the remainder of the integrated control system.

b. In track - the value of actual generated megawatts is transferred to the remainder of the integrated control system as the demand signal. The following conditions cause track:

(1) reactor trip
(2) generator output breakers open
(3) electro-hydraulic control in manual

(a) turbine trip
(b) turbine in other than ICS control

(4) Diamond rod control station in manual
(5) major integrated control system hand/automatic stations in manual
(a) reactor demand
(b) steam generator/reactor master
(c) both loop A and B feedwater demands

(6) feedwater flow greater than feedwater demand by 5%
(7) reactor or feedwater cross limits

2. Integrated master tracking relay - T_2

a. Normal condition - allows header pressure setpoint modification.
b. In track - bleeds setpoint modification to zero (no modification) through an R-C network with a time constant of 100 sec.

TABLE 9-2 (Continued)

3. Bias selection - T_3,T_4, T_5, T_6, and T_7

   a. Always selects reactor trip bias when the reactor is tripped.
   b. When the reactor is not tripped, selects turbine trip bias when:
      (1) the turbine is tripped
      OR
      (2) normal bias criteria are not met.
   c. When the reactor and turbine are not tripped, selects normal bias when:
      (1) turbine bypass valves are closed AND header pressure error is < 10 psi
      OR
      (2) unit load demand >15%.

4. Condenser interlock - T_8

   a. Normal condition - passes pressure error (minus bias value) signal to turbine bypass valves.
   b. Closes turbine bypass valves if the following conditions exist:

      (1) low circulation water flow
      (2) condenser pressure higher than setpoint

5. Feedwater demand reactor trip - T_{10} and T_{11}

   a. Normal condition - transfers feedwater demand to feedwater regulating valves.
   b. Reactor trip—transfers low level limits signal to feedwater regulating valves when the reactor trips.

6. Feedwater demand low-level limit selection - T_{12} and T_{13}

   a. 2-ft level setpoint is selected if any reactor coolant pump is running.
   b. 6-ft level setpoint is selected if all reactor coolant pumps are tripped.

7. Reactor demand T_{ave} transfer - T_{14}

   a. Normal condition—allows the reactor demand subassembly to control T_{ave}.
   b. Feedwater control—transfers T_{ave} error to feedwater demand if either the reactor demand hand/automatic (H/A) station or Diamond rod control station is in manual provided that

      (1) at least one once-through steam generator is not on low level limits.
      (2) at least one feedwater demand station is in automatic.

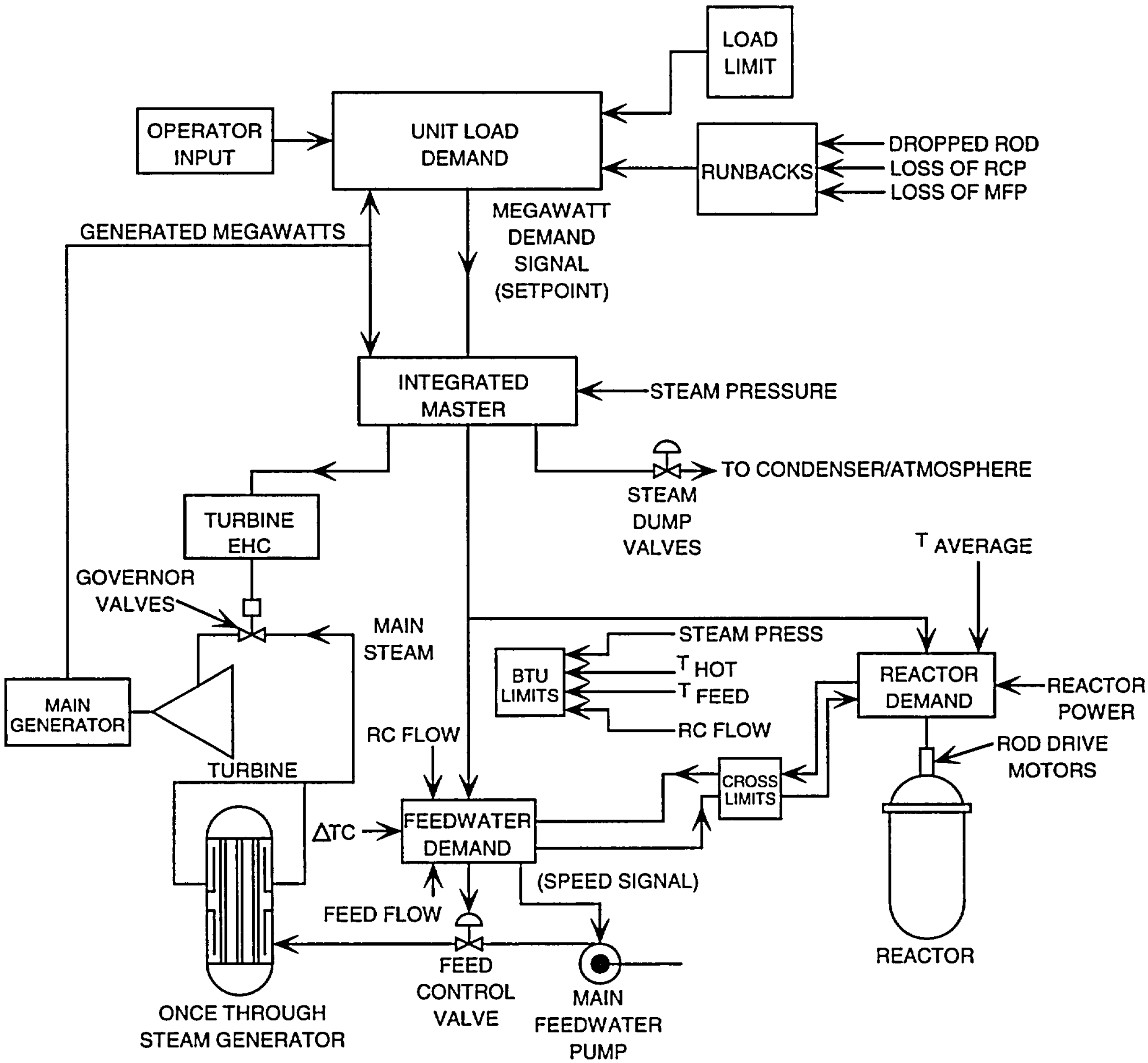

Figure 9-1 Simplified Integrated Control System

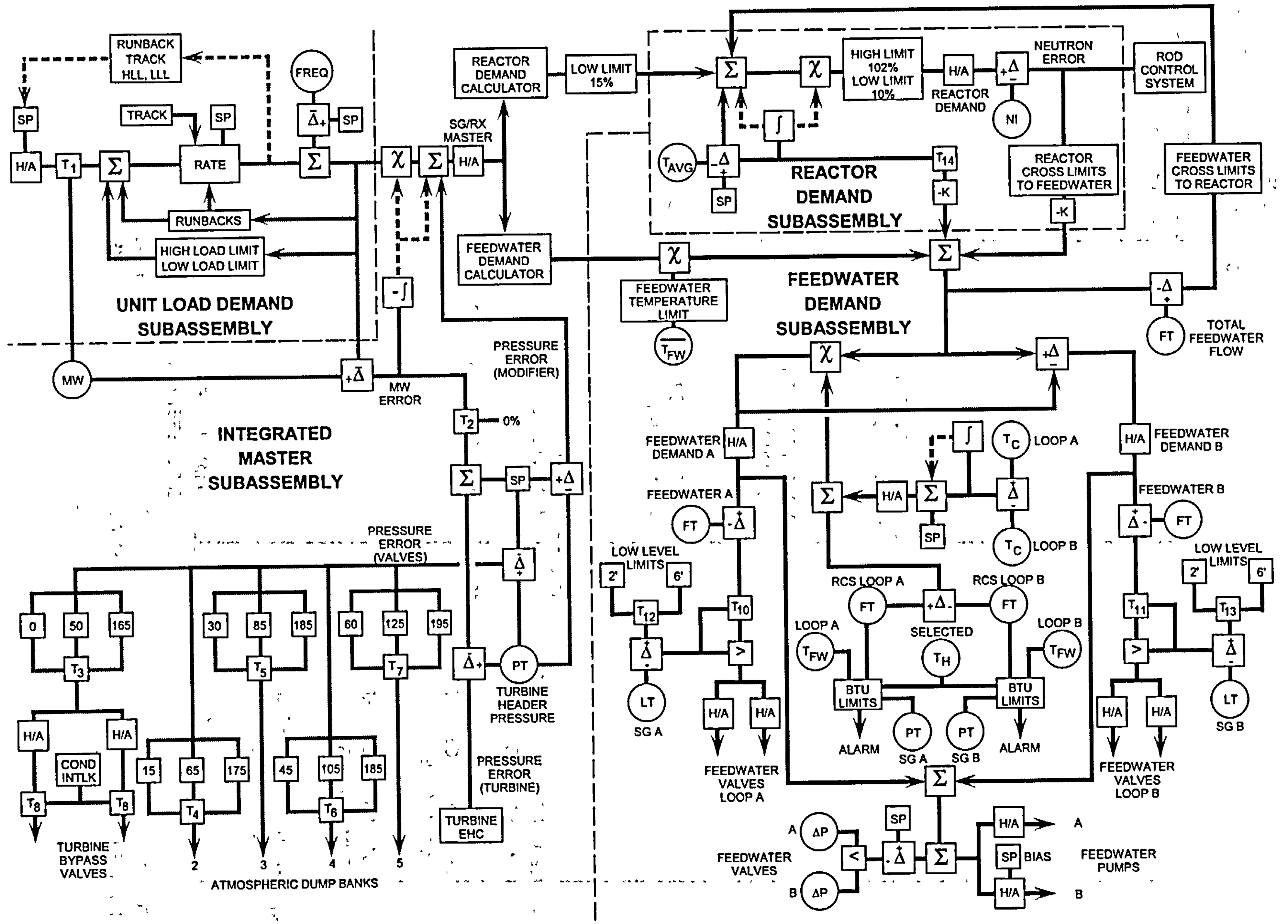

Figure 9-2 Integrated Control System

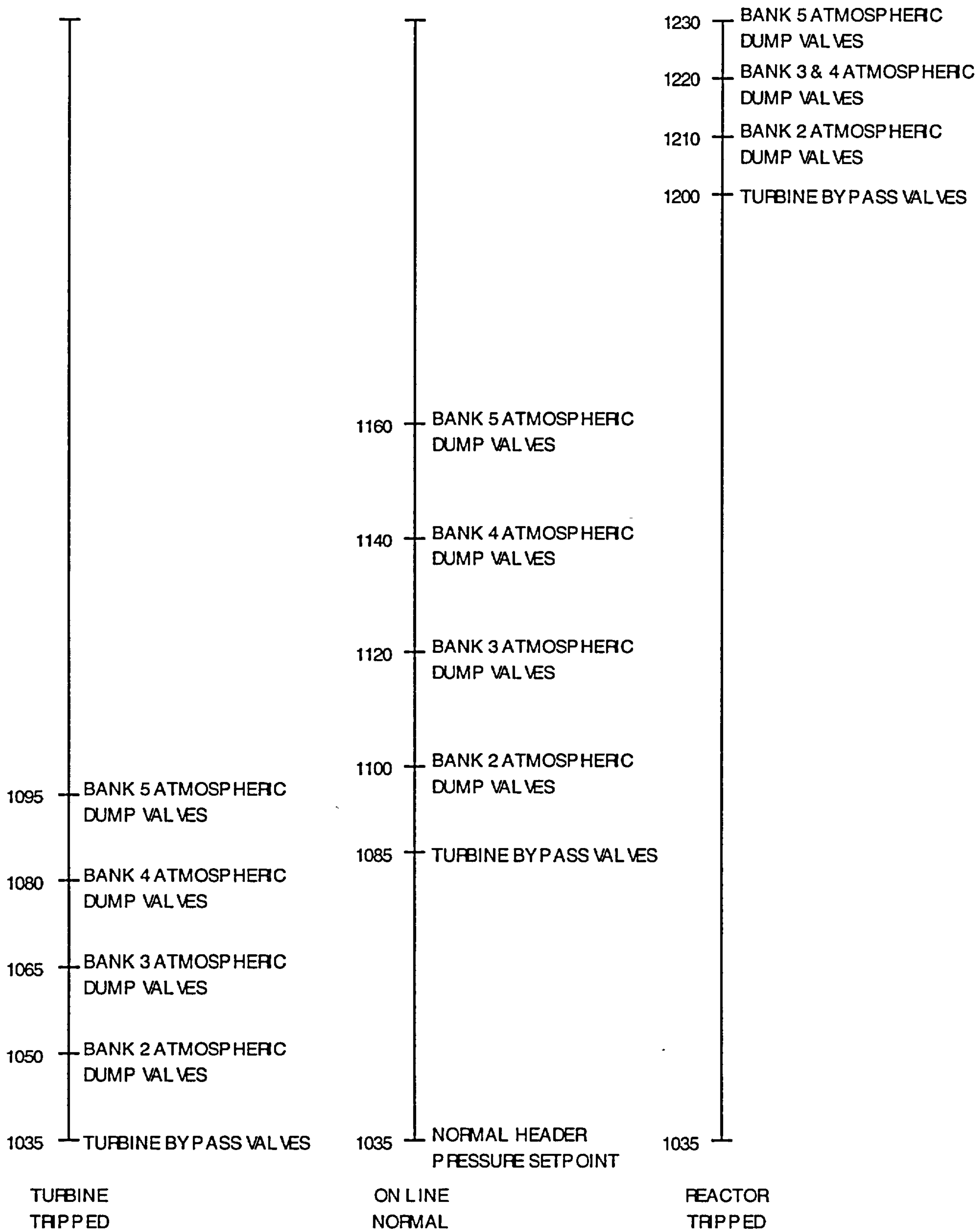

Figure 9-3 Steam Dump Setpoints

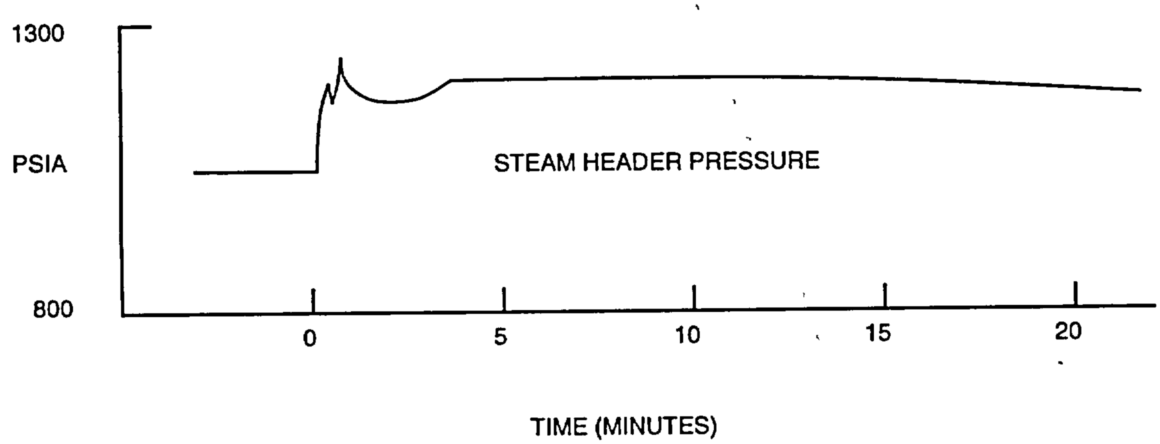

Figure 9-4 Response of Steam Pressure on a Reactor Trip

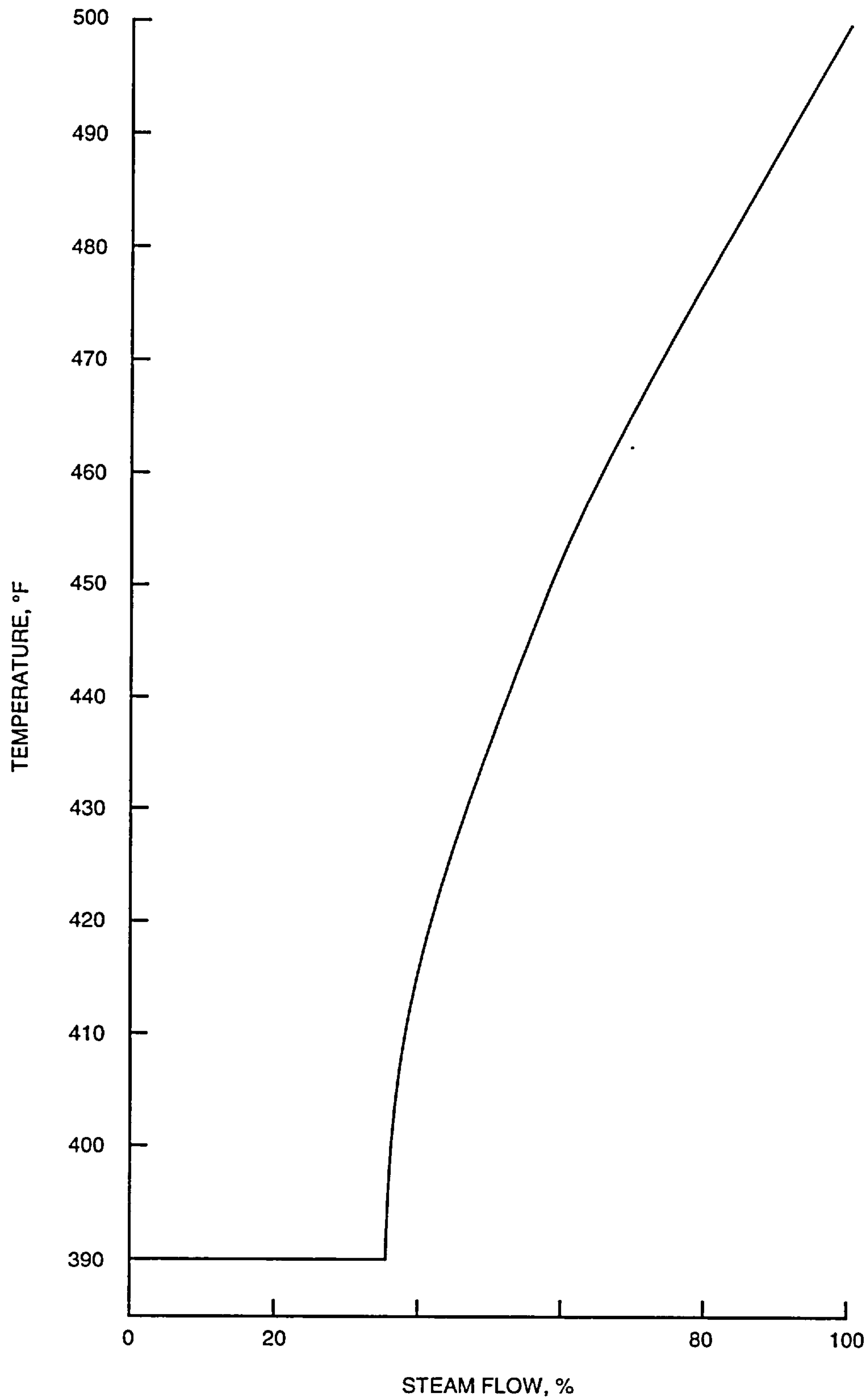

Figure 9-5 Feedwater Temperature Versus Steam Flow

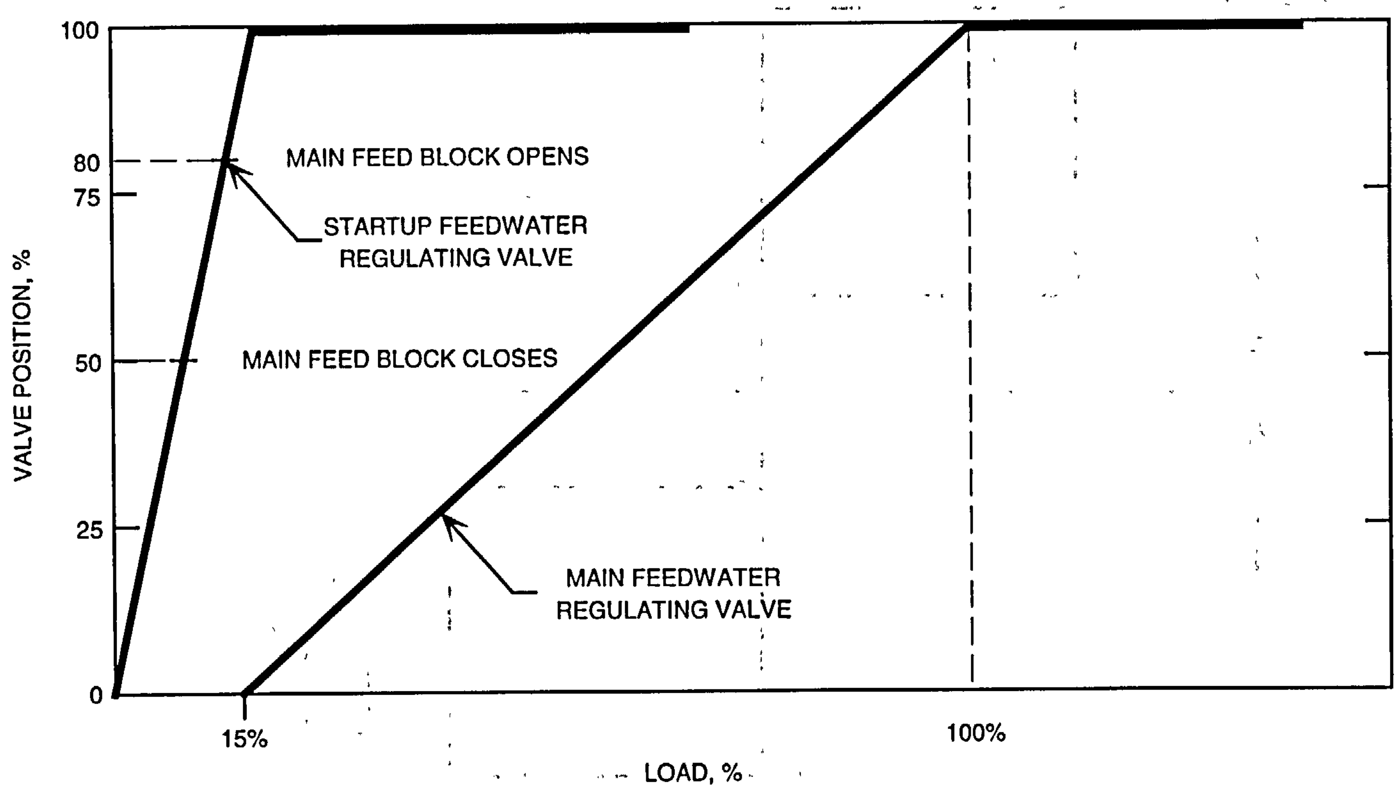

Figure 9-6 Feedwater Regulating Valve Sequence

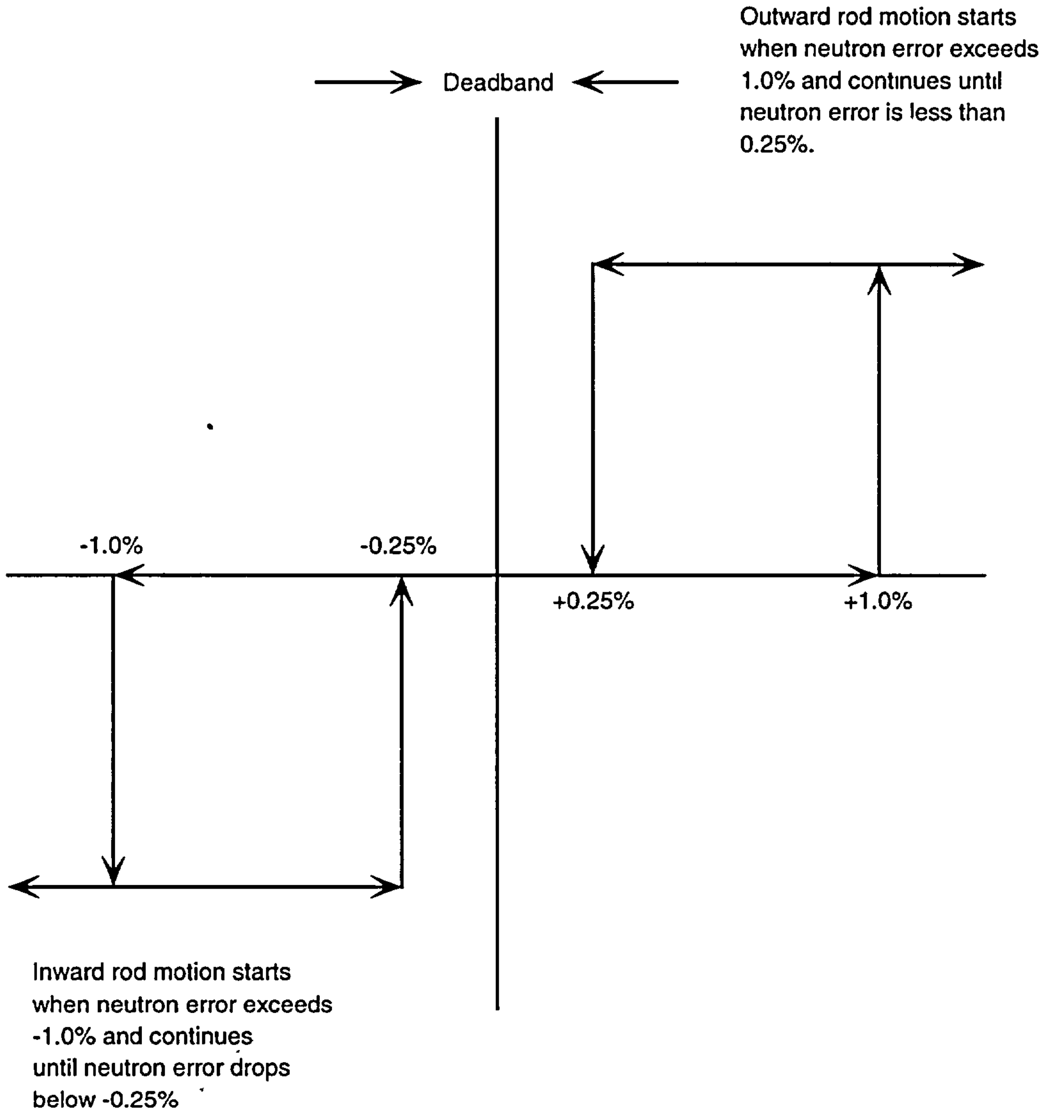

Figure 9-7 Rod Motion Versus Neutron Error

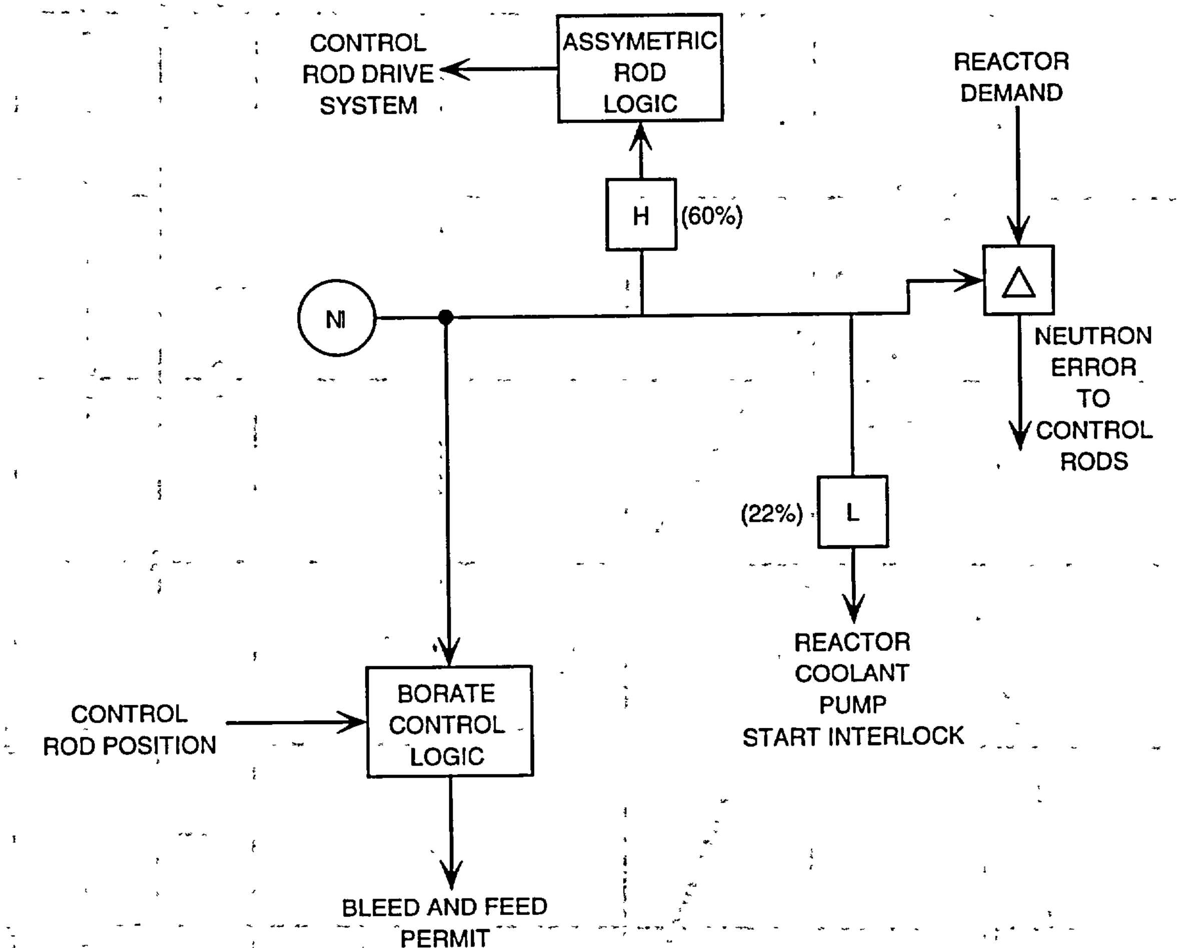

Figure 9-8 Reactor Demand Subassembly Interlocks

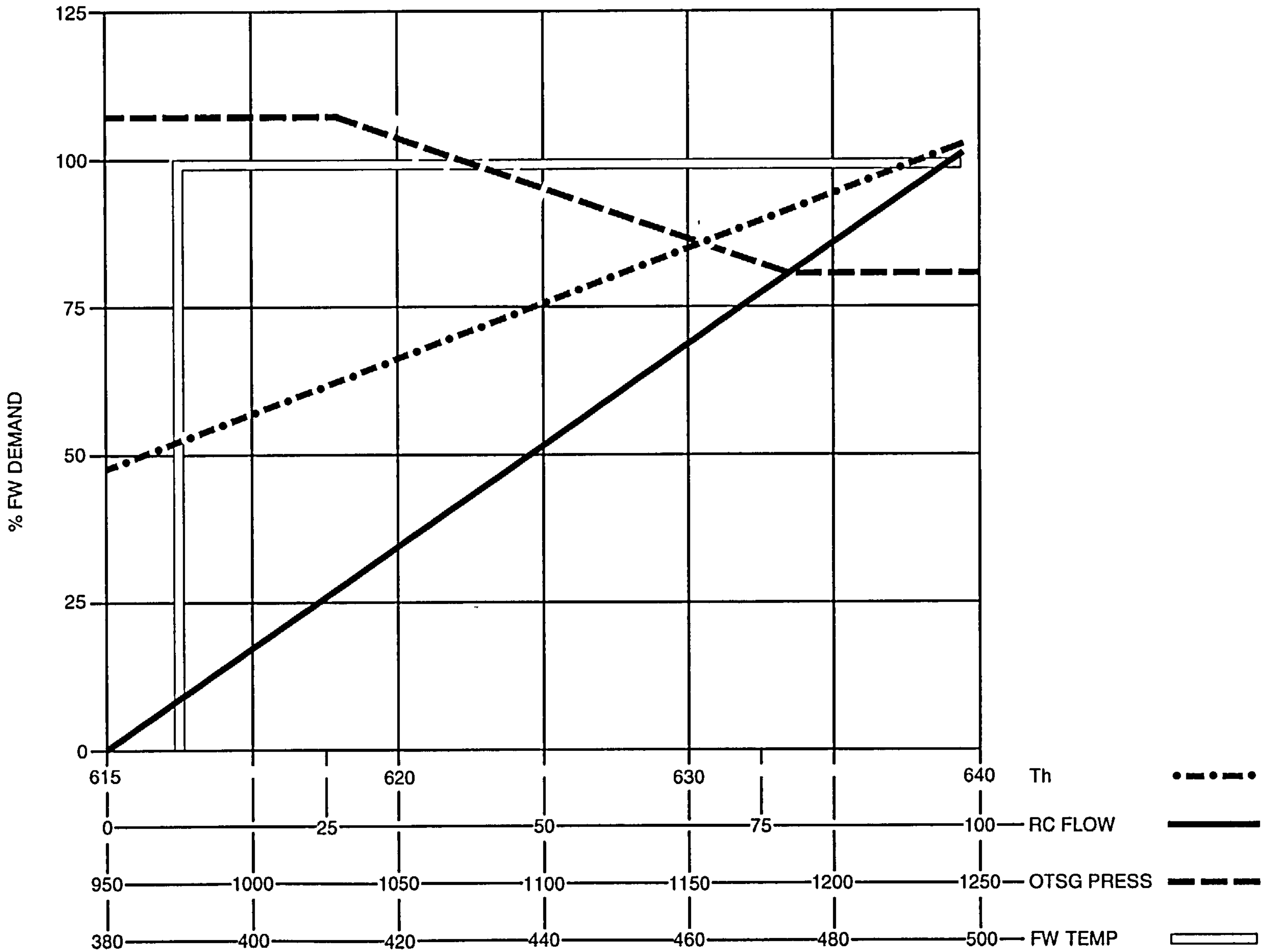

Figure 9-9 BTU Limits

BABCOCK AND WILCOX
CROSS TRAINING MANUAL

CHAPTER 10

10.1 Reactor Protection System

10.2 Engineered Safety Features Actuation System

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10.1 REACTOR PROTECTION SYSTEM

Learning Objectives:

1. State the purpose of the reactor protection system (RPS).

2. Explain how the following design features are incorporated into the RPS:

    a. Single failure criterion
    b. Testability
    c. Equipment qualification (environment, power, etc.)
    d. Independence
    e. Redundancy

3. Given a list of reactor trip signals, explain the basis for each.

4. Describe the sequence of events that occur during a reactor trip from the sensor to the trip breaker, including the normal RPS logic.

5. Explain when the channel bypass and shutdown bypass features are used and what effects each have on the RPS, including any changes in the RPS logic.

6. Describe the trip circuit breaker logic used to interrupt power to the control rod drive mechanisms, and explain why failures in the rod control system do not affect the reactor trip capability.

10.1.1 Introduction

The purpose of the RPS is to protect the barriers that prevent the release of radioactive fission products to the general public during anticipated operational occurrences (General Design Criterion 20). The barriers protected by the RPS are the fuel cladding and reactor coolant pressure boundary. Anticipated operational occurrences are defined (10 CFR 50, Appendix A) as events that are expected to occur during the design lifetime (40 years) of the plant and include such events as a loss of reactor coolant flow, loss of main feedwater, and reactivity excursions.

Barrier protection during anticipated operational occurrences can be ensured by placing limits on reactor coolant system (RCS) pressure, fuel centerline temperature, and departure from nucleate boiling ratio (DNBR), and by ensuring that these limits are not violated. Maximum values of system pressure and fuel centerline temperature and a minimum value for DNBR are provided as safety limits plant technical specifications. The RPS ensures that these safety limits are not exceeded.

The safety limit for reactor coolant pressure ensures that the integrity of the RCS is maintained. The safety limit associated with fuel centerline temperature prevents fuel melting, which could lead to the destruction of the fuel cladding. The minimum DNBR limit ensures that departure from nucleate boiling will not occur. This limit protects the cladding from high-temperature induced failures resulting from the large reduction in cladding to water heat transfer, which occurs at the onset of departure from nucleate boiling.

The RPS prevents any of the above limits from being exceeded by interrupting power to the control rod drives, allowing the control rods (groups 1 through 7) to drop into the core and shut down the reactor. The system consists of four independent and redundant channels that receive the necessary inputs to ensure that safety limits are not exceeded. The inputs to the RPS are neutron power, axial power imbalance, hot leg temperature, RCS pressure, reactor coolant flow, reactor building pressure, reactor coolant pump (RCP) status, main turbine status, and main feedwater pump status. Separate sensors for each of the four channels sense that an input parameter has exceeded its setpoint, power will be interrupted to the control rods. This interruption of power to the control rods is defined as a reactor trip. The logic used is that whenever any two our of four channels agree that a safe operating condition limit has been exceeded, a signal is processed to open the reactor trip breakers.

B&W plants have been provided with two different RPS designs. The initial design is the one used by most of the plants and is the one discussed in this section. The latest design (RPS-II) was incorporated for later 177 (Davis Besse, Midland 1&2) and the 205 fuel assembly (F/A) plants. The major differences are briefly addressed. The trip functions remain the same, except that RPS-II incorporates optical isolation, solid state devices in the channel trip logic, and a calculating module (digital) to compute certain reactor trip functions. The optical isolation is performed by use of phototransmitters, photoreceivers, and fiber optic cables, which serve to separate nonclass 1E signal paths from the class 1E signals. Relays in the trip logic have been replaced by solid state devices. A calculating module (for DNBR, pump status, and offset trips) has replaced the overpower trip (based on flow and axial imbalance), the power/pumps trip, and variable low pressure trip. The later design was developed to allow computation of more complex protection system functions and to provide the flexibility associated with a programmable digital computer. Channel bistables and reactor trip module relays have been replaced with solid state devices to extend the capability of the RPS by raising the system's immunity to seismic disturbances and to provide faster response times to action signals. In addition, the solid state devices eliminate the moving parts found in relay applications.

10.1.2 System Design Criteria

Since the RPS protects the core from damage, the design criteria applied are extensive and restrictive to guarantee reliable operation. The entire system is designed to meet or exceed the requirements set forth in IEEE 279, "Criteria for Nuclear Power Plant Protection Systems."

1. Single Failure: No single failure shall prevent a protective system from fulfilling its protective functions when action is required (General Design Criteria 21 and 23). In addition, although not required by IEEE 279, the system must meet the plant reliability criterion that no single failure shall initiate unnecessary protective system action whenever implementation does not conflict with the single failure criterion of IEEE 279.

2. Redundancy: All RPS functions are implemented by redundant sensors, measuring channels, logic, and action devices.

3. Independence: Redundant RPS channels are electrically independent and packaged to provide physical separation per General Design Criterion 22 (including separation from control systems per General Design Criterion 24). The use of buffer assemblies (or optical isolators) affords the required separation between class 1E and nonclass 1E systems.

4. Testability: Manual test facilities shall be built into the RPS (General Design Criterion 21) and its inputs and outputs to provide for preoperational testing to give assurance that the system can fulfill its required protective functions. The RPS must also provide on-line testing to prove operability and demonstrate reliability, without interfering with normal reactor or plant operation or trip functions.

5. Equipment Qualification: A wide range of environmental qualification tests, performance tests, etc. are employed to ensure equipment survivability under accident (loss-of-coolant accident [LOCA]) environments. The test results demonstrate that the equipment meets General Design Criterion 22. Protection system sensor equipment within the reactor building but outside the primary shield shall be designed for continuous operation. This equipment must also withstand the superimposed accident dose with the associated environment for the length of time the equipment is required to operate following a LOCA or steamline break (including instrument errors).

10.1.3 Reactor Trips

The RPS generates the following reactor trips:

1. high reactor power,
2. nuclear overpower based on RCS flow and axial imbalance,
3. power to pumps,
4. high T_h,
5. high RCS pressure,
6. low RCS pressure,
7. variable low RCS pressure,
8. high reactor building pressure,
9. loss of main feedwater, and
10. turbine trip.

The protection provided by each of these trips is discussed in this section.

10.1.3.1 High Reactor Power Trip

The high reactor power trip functions to prevent core damage during reactivity excursions that occur too rapidly to provide protection by sensing a change in RCS pressure or temperature. A rod ejection, a multiple group rod withdrawal accident, and an end-of-life steamline break are examples of reactivity excursions for which the high reactor power trip is the primary protection.

The high power trip also establishes an upper power bound for flux/delta flux/flow protection and for design calculations for DNBR considerations. The high power trip signal is based on heat balance corrected excore nuclear flux indication. When measured reactor power exceeds the setpoint (105.5%), a trip signal is generated.

10.1.3.2 Nuclear Overpower Trip Based on RCS Flow and Axial Imbalance (Flux/Delta Flux/Flow)

The purpose of the flux to delta flux to flow ($\phi/\Delta\phi$/flow) trip is to prevent exceeding either kw/ft limits (excessive kw/ft generation from a fuel rod can result in high fuel centerline temperatures and fuel melting) or departure from nuclear boiling ratio (DNBR) limits. This trip can be thought of as a high power trip with its setpoint being reduced by RCS flow and/or axial imbalance (top power - bottom power). Figure 10.1-1 shows the typical trip envelope that is generated by the $\phi/\Delta\phi$/flow trip circuitry. Those combinations of power (ϕ), imbalance ($\Delta\phi$), and flow that lie outside the envelope will produce a reactor trip signal. This trip is replaced with the DNBR and offset trips in the 205 F/A RPS.

10.1.3.3 Power to Pumps Trip

This trip prevents DNBR from dropping below 1.30 by tripping the reactor when pumping power is lost. In addition, this trip limits power production if a reactor coolant pump is operating in each loop and prevents single loop operation. The setpoints for various pump combinations are listed in Table 10.1-1.

10.1.3.4 High T_h Trip

The high hot leg temperature trip prevents the reactor from being operated above a fixed outlet temperature. The fixed temperature limit defines the effective range of the variable low RCS pressure trip. The high temperature trip setpoint is 644°F. The high temperature trip is not required as the primary protection for any transient, but it provides backup protection for the overpower and high RCS pressure trips.

10.1.3.5 High RCS Pressure Trip

The function of the high RCS pressure trip is to ensure that the reactor coolant pressure safety limit is not exceeded (which helps provide pressure boundary protection). The high pressure trip provides primary protection for anticipated operational occurrences which provide slow reactivity insertions, such as single rod withdrawal accidents, boron dilution accidents, and undercooling events. The high pressure trip setpoint of 2370 psig provides a margin between maximum operating RCS pressure and the set pressure of the pressurizer safety valves (2500 psig). In addition, the high pressure setpoint provides an upper pressure boundary for the calculation of DNBR.

10.1.3.6 Low RCS Pressure Trip

The function of the low RCS pressure trip is to prevent the departure from nucleate boiling and to mitigate the circumstances of pressure decreasing transients such as steam generator tube ruptures, steamline breaks, and loss-of-coolant accidents. The low RCS pressure trip helps to mitigate the consequences of the pressure decreasing transients by reducing power to decay heat levels through the reactor trip.

The low pressure trip setpoint of 2000 psig allows transients below normal operating pressure (2195 psig) without generation of unnecessary trips and provides a minimum margin above the ESFAS actuation setpoint of 1600 psig. This margin is required to provide a reasonable RCS pressure band below the low pressure trip setpoint in which the ESFAS can be bypassed when the plant is undergoing a controlled cooldown.

10.1.3.7 Variable Low RCS Pressure Trip

This trip provides DNB protection for the core. As shown in Figure 10.1-2, the trip provides a margin to DNB for a combination of pressures and temperatures that are not covered by the low RCS pressure or high T_h trip.

10.1.3.8 High Reactor Building Pressure Trip

This trip functions to ensure that the reactor is shut down in the event of a loss-of-coolant accident.

10.1.3.9 Anticipatory Loss of Main Feedwater Trip

This reactor trip was added to the 177 fuel assembly units following the accident at TMI-2. The purpose of this trip is to insure that the reactor is tripped when the ability to remove the heat from the reactor is reduced due to the loss of main feedwater flow. Before the inclusion of this anticipatory trip, the loss of main feedwater event was terminated by the high RCS pressure trip.

10.1.3.10 Reactor Trip on Turbine Trip

The reactor trip on turbine trip was the second trip that was added following the TMI-2 accident. This trip functions to shut down the reactor when its heat sink (turbine) is lost.

10.1.3.11 Manual Reactor Trip

A manual reactor trip pushbutton(s) is installed to allow the operator to trip the reactor. Plant procedures will allow this option if, in the opinion of the operator, an unsafe condition exists. A summary of RPS trips, setpoints, and purposes can be found in Table 10.1-1.

10.1.4 Reactor Trip Circuitry

10.1.4.1 Power Range Excore Nuclear Instrumentation

Each power range channel consists of two detectors (Figure 10.1-3), and each of these detectors provides an input into a linear amplifier. The outputs of the two linear amplifiers supply a summing amplifier and a difference amplifier. The summing amplifier's output supplies a signal to the $\phi/\Delta\phi$/flow trip circuitry. The output of the difference amplifier supplies a signal to a function generator, where it is combined with RCS flow. Function generator slope and breakpoint adjustments are provided to generate the trip envelope. The output of the function generator is compared with total power in the trip bistable and, if required, a trip signal will be generated.

In addition to the $\phi/\Delta\phi$/flow trip, the summing amplifier output signal supplies the high power trip and the power to pumps trip. The high flux trip bistable compares the total power input with a setpoint for the trip decision. In the power to pumps trip bistable, the total power signal is compared with a setpoint that is determined by the number of operating RCPs. If total power exceeds the setpoint, then a trip signal is generated.

10.1.4.2 Temperature and Pressure Inputs

Reactor coolant outlet temperature (T_h) is used in the generation of the high T_h trip (Figure 10.1-4) and the variable low pressure trip. Each RPS channel receives one T_h input. These signals originate from resistance temperature detectors (RTDs) that are mounted in wells in the RCS piping. Each RTD is wired into a bridge circuit located in an RPS cabinet. This cabinet is used to convert the change in RTD resistance to a voltage signal that is proportional to temperature. The T_h signal is compared with a setpoint to generate the high T_h trip. The output of the T_h signal converter is routed to the variable low pressure trip bistable for generation of this trip.

RCS pressure is sensed by pressure transmitters piped to taps on each reactor outlet line. Two transmitters tap into the A hot leg, and the remaining two transmitters tap into the B hot leg. Each of the four RPS channels supplies power to one pressure transmitter and in turn receives an input from that transmitter. The output of each pressure transmitter is supplied to a buffer amplifier. The buffer amplifier receives, amplifies, and converts the 4- to 20-ma transmitter signal to a 0- to 10-vdc analog signal proportional to RCS pressure, with a scaled range from 1500 to 2500 psig. The voltage signal from the buffer amplifier supplies an input to the high pressure trip bistable, the low pressure trip bistable, the shutdown bypass trip bistable, and the variable low pressure trip bistable. In each of the bistables, a comparison is made between actual RCS pressure and a setpoint. If the setpoint is exceeded, a trip signal will be issued by the bistable.

10.1.4.3 Reactor Building Pressure Input

Reactor building (RB) pressure is compared with a setpoint in a bistable to generate a reactor trip signal. At some plants, the high RB pressure trip is generated by pressure switches located inside the reactor building.

10.1.4.4 Anticipatory Trip Circuitry

The loss of main feed pumps and turbine trips consist of contact inputs that are in series with the channel trip relay. Since the loss of feed pumps and turbine reactor trips are not in service at low power levels, parallel power range bistable contacts bypass these trips until power is above their setpoints (40%). As shown in Figure 10.1-5, if both feed pump contacts open and reactor power is greater than 40%, the channel trip relay will deenergize. The turbine trip works in a similar fashion. It should be noted that the total power contacts in parallel with the main feed pump contacts and the turbine trip contact bypass the anticipatory trips if power is less than 40%. In this case, the total power contacts are closed and the opening of both main feed pump contacts or the turbine trip contact will not de-energize the channel trip relay.

10.1.4.5 RCS Flow

RCS flow from each of the hot legs is transmitted to the RPS. In the RPS, the individual flow signals are summed, and the total flow signal is used in the generation of the $\phi/\Delta\phi$/flow trip.

10.1.5 RPS Channel Logic

The RPS trip scheme consists of series contacts that are operated by bistables. Refer to Figure 10.1-6, using RPS channel A as an example. During normal plant operations, all contacts are closed and the channel trip relay (KA) remains energized. However, if any trip parameter (in channel A) exceeds its setpoint, its associated contact opens and de-energizes the channel trip relay. When the channel trip relay de-energizes, several actions occur:

1. The KA relay deenergizes the four (4) output logic relays (KA1, KA2, KA3, and KA4). Each of these relays "informs" its associated RPS channel that a reactor trip signal has occurred in RPS channel A.
2. The KA1 contacts in the undervoltage (UV) coil circuitry powered by RPS channel A open, but the undervoltage coil remains energized through the closed KB1, KC1, and KD1 contacts. This condition exists in each RPS channel (except that the contact designations are different). Each RPS channel controls an undervoltage (UV) coil on a reactor trip circuit breaker.
3. The KA contact in parallel with the channel reset switch opens, and the trip is sealed in. The channel reset switch must be depressed, after the trip condition has cleared, to re-energize the channel trip relay and thus restore the RPS channel to its normal (non-tripped) configuration.

While the information presented is associated only with RPS channel A, it is applicable for any RPS channel. Also, even though channel A has sensed a reactor trip condition, the reactor has not tripped. When the second RPS channel senses a reactor trip condition, the following occurs:

1. The channel trip relay for that channel de-energizes.
2. The output logic relays for the second channel de-energize and open contacts that supply power to the reactor trip circuit breaker UV coils.
3. With contacts opened by two separate RPS channels, power is interrupted to the reactor trip circuit breaker UV coils and the breakers open. When the breakers open, the control rods fall into the core.

In the preceding discussion, two key points should be remembered. First, a minimum of two out of four channels must sense a trip condition to cause a reactor trip. This logic is satisfied by the eight series/parallel contacts in the reactor trip circuit breaker UV coil circuitry. The second point is that a coincidence trip logic does not exist. Since the bistable relay contacts are in series with the channel trip relays, two unrelated channel trips can result in a reactor trip.

10.1.6 Reactor Trip Circuit Breaker Logic

Power is supplied to the control rods (Figure 10.1-7) from two separate plant sources through the ac trip circuit breakers. These breakers are designated A and B, and their undervoltage coils are powered by RPS channels A and B, respectively. From the circuit breakers, the control rod drive (CRD) power travels through voltage regulators and stepdown transformers. These devices, in turn, supply redundant busses that feed the dc power supplies for the safety rods and the regulating rod power supplies.

The dc power supplies rectify the ac input and supply power to hold the safety rods in their fully withdrawn position. One of the redundant power supplies powers phase A, and the other phase CC. Either phase being energized is sufficient to hold the rod. Two breakers are located on the output of each power supply. Each breaker controls power to two of the four safety rod groups. The undervoltage coils on the two circuit breakers on the output of one of the power supplies are controlled by RPS channel C, and the other two breakers are controlled by RPS channel D.

In addition to the dc power supplies, the redundant busses also supply power to the regulating and auxiliary power supplies. These power supplies consist of silicon control rectifiers (SCRs) that are gated on by programming lamps. (The SCRs as well as the programming lamps are redundant.) If power is removed from the programming lamps, gating power is lost to the SCRs, and they cease to supply power to the regulating rods. Programming lamp power is controlled by contactors (E and F) which are controlled by RPS power. One of the redundant programming lamp supplies is controlled by RPS channel C, and the other supply is controlled by RPS channel D.

One ac breaker and two dc breakers are in series in one of the power supplies, and the redundant ac breaker and dc breakers are in series in the other power supply to the control rods. The logic required to cause a reactor trip is the opening of a circuit breaker in each of the redundant power supplies. (The two dc circuit breakers on the output of each power supply are treated as one breaker.) This is known as a one-out-of-two-used-twice logic. The following example illustrates the operation of the reactor trip circuit breakers:

If only the B ac breaker opens:

a. The input power to the associated dc power supply is lost and the "CC" phase to the safety rods de-energize.

b. The SCR supply from the associated power source is lost and the redundant power supply to the regulating rods de-energize.

If only the C dc breaker(s) and E contactor open:

a. The output of the redundant dc power supply is lost and the "A" phase to the safety rods de-energize

b. When the E contactor opens, program-ming lamp power is lost to the redundant rectifying bank is lost to the regulating rods.

The combination of the opening of the B ac breaker, the C dc breaker(s), and the E contactor causes a reactor trip. Any other combination of at least one circuit breaker opening in each power supply will cause a reactor trip.

To summarize the last two sections, assume that RPS channel B senses a low RCS pressure condition and RPS channel C senses a variable low RCS pressure condition. When the channel B bistable relay de-energizes, the channel trip relay deenergizes and opens its associated contacts. The same thing occurs in channel C, except that the variable low RCS pressure bistable relay deenergizes the C channel trip relay. When the output logic relays deenergize, the B and C contacts in the UV and E/F contactor circuits open. When the UV coils and E/F contactors de-energize, all circuit breakers open, and programming lamp power is removed. All rods fall into the core, resulting in a reactor trip.

10.1.7 System Testing

To ensure the operability of the RPS, plant technical specifications require the monthly testing of each RPS channel. The analog trips in the RPS can be tested with an installed test power supply that is substituted for the detector output. The output of the test power supply is increased to the trip setpoint to verify the operability of the associated buffer amplifier(s) and bistable trip units. The test panel allows the testing of analog inputs (pressure, temperature, and power) and contact inputs (pump status monitor). Individual test modules can be operated without causing a channel trip, if the channel is in channel bypass (Section 10.1.8).

As shown in Figure 10.1-6, the primary sources of 120-vac power for the RPS are the four vital instrument buses. Each channel is powered from a different vital bus. Within the system cabinets, each RPS channel is powered by separate plus and minus 15-vdc channel power supplies. All trip devices operate in a normally energized state and go to a de-energized state to initiate trip action. Loss of power thus automatically forces the bistables into the tripped state. In addition, the loss of power to the channel trip relay would place it in a de-energized or tripped condition. Failure of a vital bus or a channel power supply causes the affected channel to trip.

The removal of any module required to perform a protective function initiates the trip normally associated with that portion of the system. For example, removal of a trip bistable trips the associated channel terminating device, and removal of a reactor trip module trips the associated CRD breaker. Removing a trip bistable breaks the trip chain leading to the channel trip relay, and a one-out-of-four trip input is sent to the other three channels.

10.1.7.1 Module Interlocks and Test Trip Relay

The entire RPS in simplified form is shown in Figure 10.1-6. In the preceding sections, each component element of the RPS has been discussed. The last remaining objective is to acquire an understanding of the module interlocks and test trip relay, identified for channel D. Each channel and each trip module is capable of being individually tested. When a module is placed into the test mode, it causes the test trip relay to open the TT contact and to indicate an RPS channel trip. Under normal conditions the channel to be tested is placed in bypass before a module is tested.

The use of two-out-of-four logic between channels permits a channel to be tested on-line without initiating a reactor trip. Maintenance to the extent of removing and replacing any module within a channel may also be accomplished in the on-line state without a reactor trip. To prevent either on-line testing or maintenance features from creating a means for unintentionally negating protective action, a system of interlocks initiates a channel trip when a module is placed in the test mode or is removed from the system (unless the system is bypassed).

10.1.7.2 Bistable Modules

Bistable modules (Figure 10.1-8) are used to convert analog input signals to digital output signals in the form of relay contacts when setpoint values are reached. The bistable can be connected to trip on either an increasing or decreasing signal. An adjustable deadband, or hysteresis, is included to ensure positive switching action at the trip setpoint, even with noise or small variations present in the input signal. A memory circuit, which must be reset manually, is included to indicate whether the bistable module has been tripped or not. On the front plate are lights to indicate the trip state of the bistable and the state of the bistable memory. These indicating lamps are normally "dim" to reflect that power is available and that the bistable is in a normal or non-tripped condition. "Bright" indicating lamps signify that the bistable has been tripped. There are two momentary toggle switches for resetting the state and also the memory. Two potentiometers with turn counting dials are used for adjusting the setpoint of the bistable and the deadband. Test jacks are provided for measuring the input, setpoint, and deadband voltages.

The test scheme for the RPS is based on the use of comparative measurements between like variables in the four channels, and the substitution of externally introduced digital and analog signals as required, together with measurements of actual protective function trip setpoints. A digital voltmeter is provided for making accurate measurements of the trip setpoints and analog voltage signals. The test circuits allow the operator to test system channels from the input of any bistable up to the final actuating device at any time during reactor operation.

The bistable test consists of inserting an analog input from one of the channel test modules (Figure 10.1-9) and varying the input until the bistable setpoint is reached. The value of the inserted test signal, as monitored by the analog indicator as well as the digital voltmeter, represents the true value of the bistable setpoint. Thus, the test verifies not only that the bistable functions, but also that the setpoint is correctly set. During the test, satisfactory operation of the bistable can be observed by watching the trip status light in the reactor trip module (Figure 10.1-10). The reactor trip module two-out-of-four logic and the associated control rod drive breaker are tested by pressing various combinations of two logic test switches in the reactor trip module to simulate the six combinations of trips inherent in a two-out-of-four coincidence logic. Satisfactory performance of the trip logic relays can be observed by watching the trip logic relay lights and the breaker trip lights on the reactor trip module. This test verifies not only all the combinations of the two-out-of-four logic, but also that the trip logic relays and the control rod breakers will trip.

The system test scheme includes frequent visual checks and comparisons within the system on a regular schedule in which all channels are checked at one time, together with less frequent electrical tests conducted on a rotational plan in which the tests are conducted on different channels at different times, as encouraged by the PRA to minimize common mode failure items.

10.1.8 RPS Bypasses

The two types of bypasses are RPS channel bypass and RPS shutdown bypass. Channel bypass provides a method of placing one RPS channel in a cannot trip condition, and shutdown bypass provides a method of leaving the safety rods withdrawn during cooldown and depressurization of the RCS. Each of these bypasses is discussed below.

10.1.8.1 Channel Bypass

A channel bypass (Figure 10.1-6) provision is provided to allow for maintenance and testing of the RPS. The use of channel bypass keeps the channel trip relay energized regardless of the status of the bistable relay contacts. To place a channel in channel bypass, the other three channels must not be in channel bypass. This is ensured by contacts from the other channels being in series with the channel bypass relay. If any contact is open, then the second channel cannot be bypassed. The second condition is the closing of the key switch on the reactor trip module (which is administratively controlled). When the bypass relay is energized, the bypass contact closes, maintaining the channel trip relay in an energized condition. All RPS trips are reduced to a 2-out-of-3 logic (of the remaining channels) when a channel is in channel bypass; this condition is continuously annunciated in the main control room. In channel bypass, the testing of trip bistables or repair of RPS modules can be performed without generating unnecessary trip signals from the affected channel.

10.1.8.2 Shutdown Bypass

During plant cooldowns it is very desirable to leave the safety rods withdrawn to provide shutdown capability in the event of unusual positive reactivity additions (moderator dilution, etc.). However, the plant is also depressurized as coolant temperature is decreased. If the safety rods are withdrawn and coolant pressure is decreased, a low RCS pressure trip will occur at 2000 psig, and the rods will fall into the core. A method is installed in the protection system that allows the operator to bypass the low RCS pressure trip and to keep safety rods withdrawn. This method is called shutdown bypass. During the cooldown and depressurization, the safety rods are inserted prior to the low RCS pressure trip (2000 psig). The RCS pressure is decreased to less than 1820 psig, and then each RPS channel is placed in shutdown bypass.

In shutdown bypass (Figure 10.1-6), the normally closed SD contact in the bistable trip string opens and the key switch SD contact closes. This action bypasses the low RCS pressure trip, $\phi/\Delta\phi$/flow trip, power to pumps trip, and the variable low RCS pressure trip and inserts a new high RCS pressure (1820 psig) trip. The operator can now withdraw the safety rods for additional shutdown margin.

The insertion of the new high pressure trip bistable performs two functions. First, with a trip setpoint of 1820 psig, the bistable prevents operation at normal system pressure (2195 psig) with a portion of the RPS bypassed. The second function ensures that the bypass is removed prior to normal operation. When the RCS pressure is increased during a plant heatup, the safety rods are inserted prior to reaching 1820 psig. The shutdown bypass is then removed, returning the RPS to normal, and system pressure is increased to greater than 2000 psig. The safety rods are then withdrawn and remain at the full-out condition for the rest of the heatup.

In addition to the shutdown bypass high RCS pressure trip, the high flux trip setpoint is administratively reduced to 5% while the RPS is in shutdown bypass. This provides a backup to the shutdown bypass high pressure trip, and allows low temperature physics testing while preventing the generation of any significant power.

10.1.9 PRA Insights

The major RPS PRA concern is an anticipated transient without scram (ATWS). According to the ANO1 PRA, the ATWS has a core melt frequency contribution of 6%. The dominant accident sequence assumes that the transient starts with all the front line systems initially available and proceeds as follows:

1. A valid trip signal is received, and a double failure of the reactor trip circuit breakers occurs.

2. The main feedwater pumps trip or run back to a low feedwater flow condition.

3. The operator fails to initiate feed and bleed core cooling.

The risk reduction factor for the RPS is 1.06, and the risk achievement factor is 56,001. The large risk achievement factor is due to the small failure probability of the RPS that is assumed in the PRA. It should be noted that the PRA study was completed before the plant was required to add the shunt trip coils to the RPS circuitry.

NRC Generic Letter 83-28 required actions based on generic implications of the Salem ATWS events, which include automatic actuation of the shunt trip devices on the CRD breakers. Class 1 relays are installed within the CRD breaker cabinets to actuate the breakers by providing power to a shunt trip. One relay is placed in each channel and is connected in parallel with the undervoltage coil on the CRD breaker (Figure 10.1-11). Control power for the shunt trip will come through contacts actuated by the shunt relay. Upon de-energization of the undervoltage and shunt relays, power will be provided to the shunt trip relay, thereby tripping the CRD breaker.

10 CFR 50.62 requires additional safety improvements in the design and operation of light water cooled nuclear power reactors to minimize the probability of an ATWS event. The new requirements reduce the likelihood of failure of the reactor trip system to scram the reactor following an ATWS and reduce the consequences should failures occur. An anticipated transient and concurrent failure of the reactor trip system could lead to melting of reactor fuel and release of large amounts of radioactivity to the environment. The new requirements for pressurized water reactors are:

1. Additional equipment, independent of the reactor trip system, to automatically activate the auxiliary feedwateer system and initiate a shutdown of the plant turbine under conditions indicative of an ATWS.

2. A diverse scram system independent of the existing reactor trip system (from sensor output to interruption of power to the control rods).

A functional diagram of a backup scram system (BSS) is shown in Figure 10.1-12. The BSS consists of two channels of instrumentation, each having a reactor coolant pressure input to a bistable with a trip setpoint of 2450 psig. The bistable output will be a contact closure that energizes BSS relays in the control rod drive control system (CRDCS) cabinets. The BSS relay output will open programmer lamp circuits, causing de-gating of one group of SCRs. A coincident second BSS channel actuation will degate a second group of SCRs, thus removing the power from the control rod drive mechanisms (CRDMs) and causing the control rods to drop into the core. Both CRDCS groups' (channels A and B) SCRs must de-energize to release the control rods.

The system is designed to be testable with the reactor on-line. While one channel is being tested, a BSS bypass switch will be actuated to prevent an inadvertent reactor trip. A means to alert the operators that a BSS channel is in a bypass or tripped condition is provided. Inadvertent actuation of the BSS will be prevented by using a two-out-of-two channel logic to initiate a reactor trip.

10.1.10 Summary

The reactor protection system is designed to protect the fuel cladding boundary and the RCS pressure boundary from damage during anticipated operational occurrences. The system consists of four separate redundant channels that receive inputs of neutron flux, axial imbalance, RCS pressure, RCS flow, RCS temperature, RB pressure, RCP status, main feedwater pump status, and main turbine status.

These input signals are received by the trip circuitry. The RPS circuitry processes these inputs and compares these values to predetermined setpoints. If a setpoint is exceeded, a trip signal is generated. The generation of any trip signal in any two of the four RPS channels will result in the tripping of the reactor.

The reactor is tripped by the opening of circuit breakers that interrupt the power supply to the control rod drives. Six breakers are installed to increase reliability and allow testing of the trip system. A one-out-of-two-used-twice logic is used to interrupt power to the rods.

The RPS has two bypasses: a shutdown bypass and a channel bypass. Shutdown bypass allows the withdrawal of safety rods for shutdown margin availability during plant cooldowns or heatups. Channel bypass is used for maintenance and testing. Test circuits in the analog and digital trip strings allow complete testing of all RPS trip functions.

TABLE 10.1-1 REACTOR TRIP SUMMARY

Trip	Setpoint	Protection Afforded
High Reactor Power	105.5%	1. Rapid reactivity excursions. 2. Upper bound for DNBR calculations.
Φ/ΔΦ/Flow	See Figure 10.1-1	1. DNBR 2. kw/ft
Reactor Power to Pumps	2/2 - >125% 1/2 - >125% 1/1 - 55% 0/2 - Automatic Trip 0/1 - Automatic Trip 0/0 - Automatic Trip	1. DNBR 2. Prevents single loop operation.
High T_h	644°F	DNBR
High RCS Pressure	2370 psig	RCS boundary protection.
Low RCS Pressure	2000 psig	DNBR
Variable Low RCS Pressure	$15.4T_h$ - 7718 psig (T_h in °F)	DNBR
High Reactor Building Pressure	4 psig	Ensures that the reactor is shut down during accidents.
Anticipatory Loss of Main Feedwater	Loss of both MFPs above 40%	1. Loss of heat sink. 2. TMI-2 requirement.
Reactor Trip on Turbine Trip	Turbine trip above 40%	1. Loss of heat sink. 2. TMI-2 requirement.

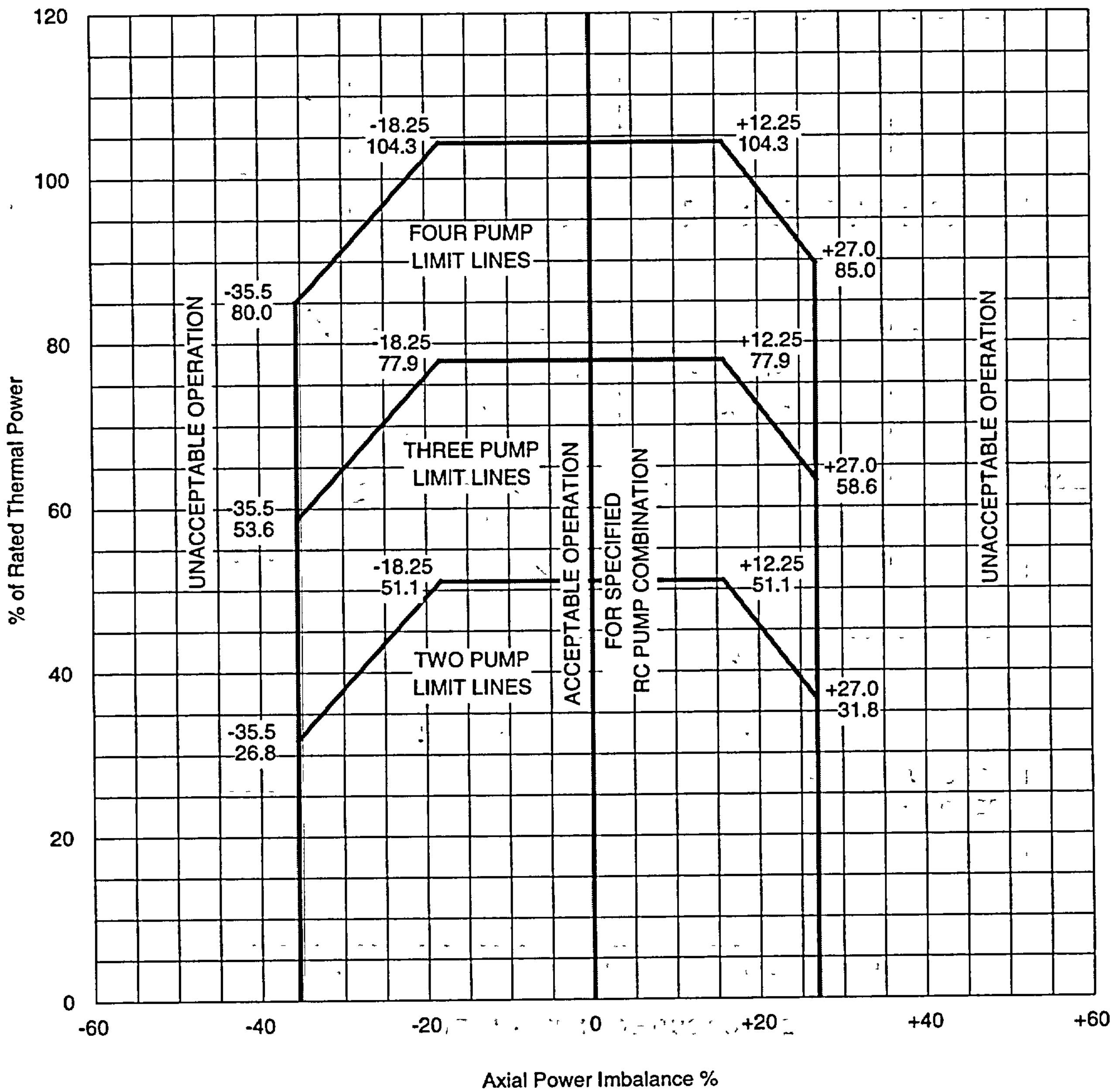


Figure 10.1-1 Flux / Delta Flux / Flow Trip Envelope

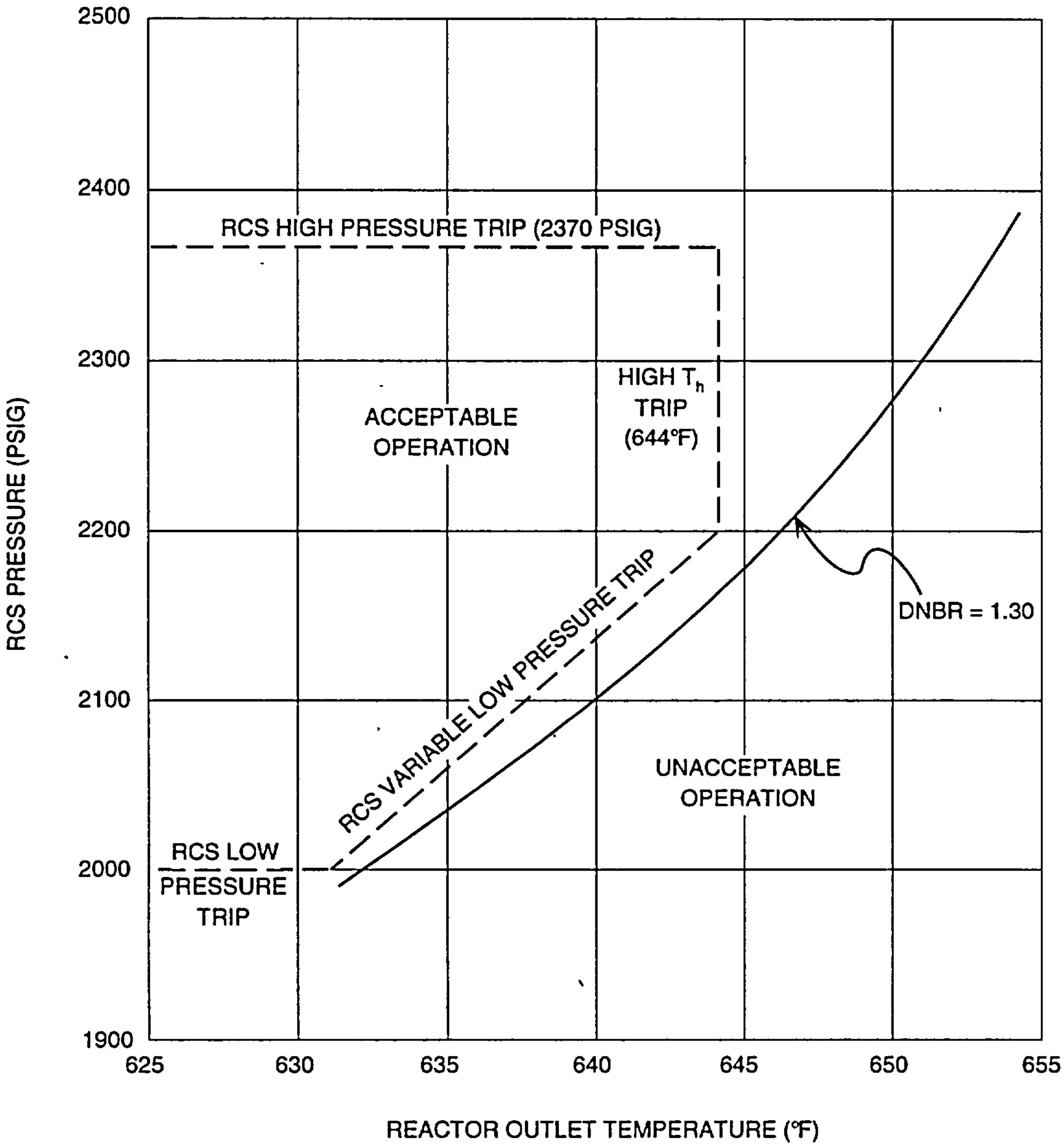


Figure 10.1-2 Pressure / Temperature Trip Envelope

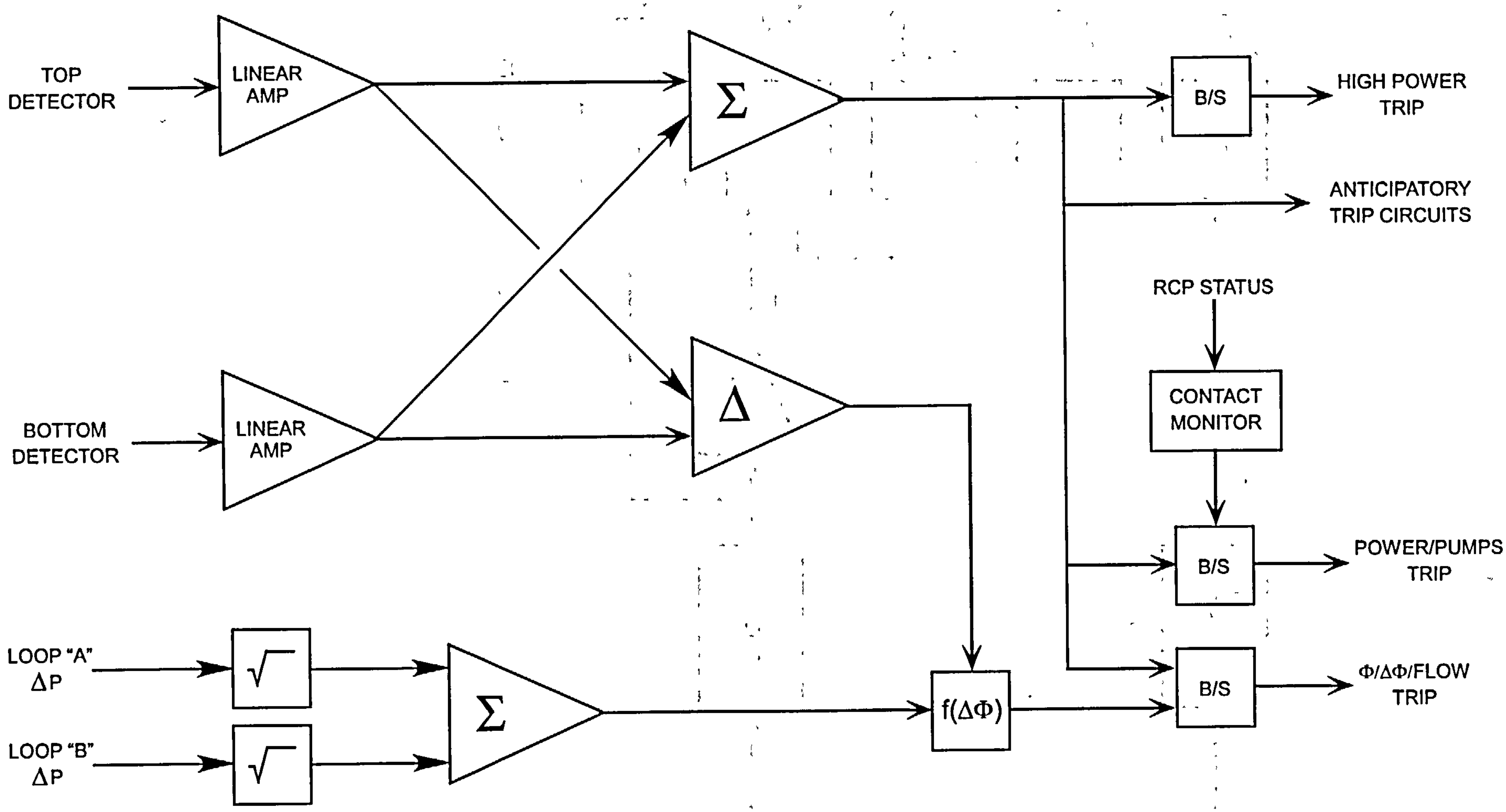


Figure 10.1-3 Excore Nuclear Instrumentation Inputs

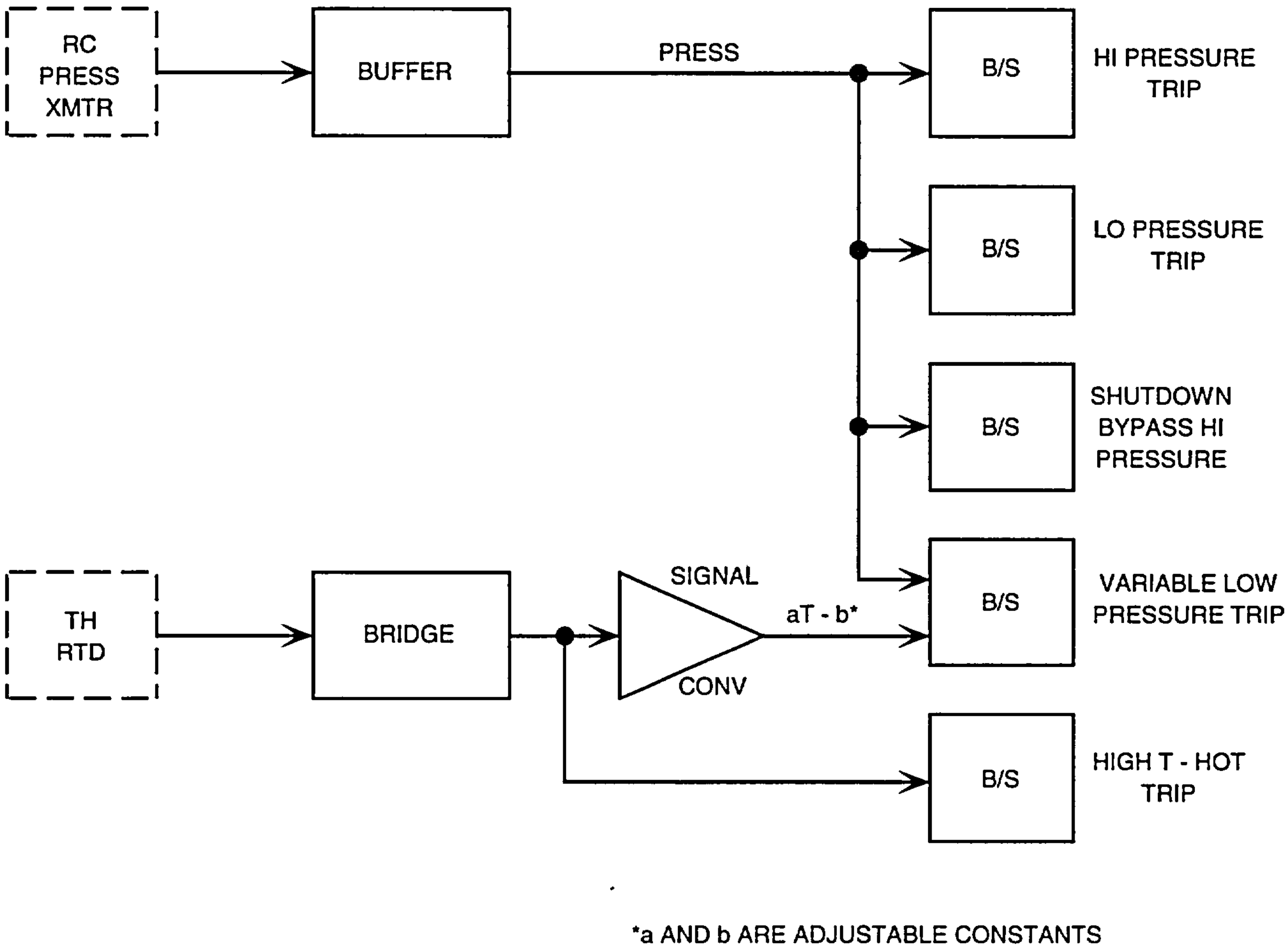


Figure 10.1-4 RPS Temperature and Pressure Inputs

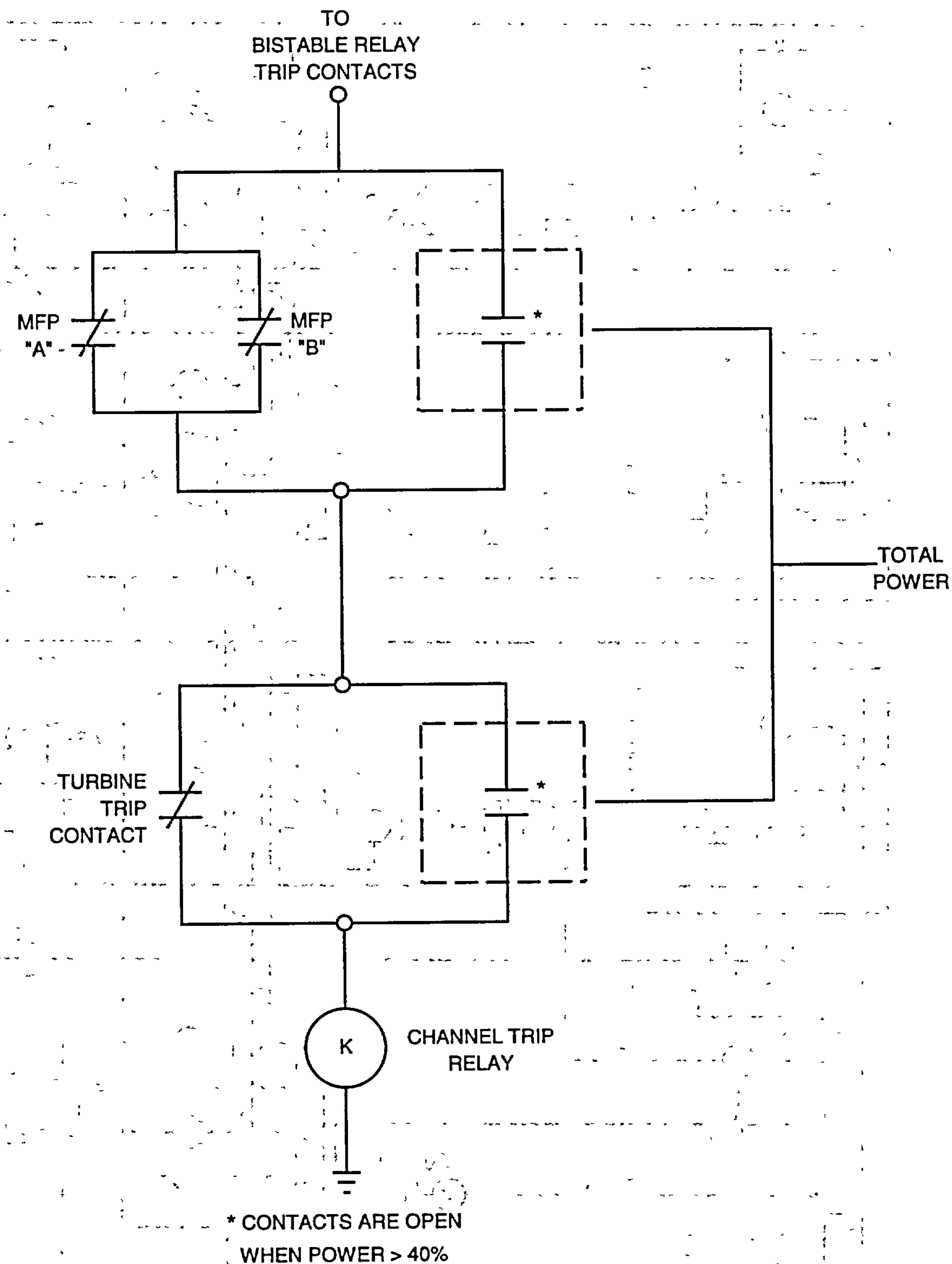


Figure 10.1-5 Anticipatory Trips Circuitry

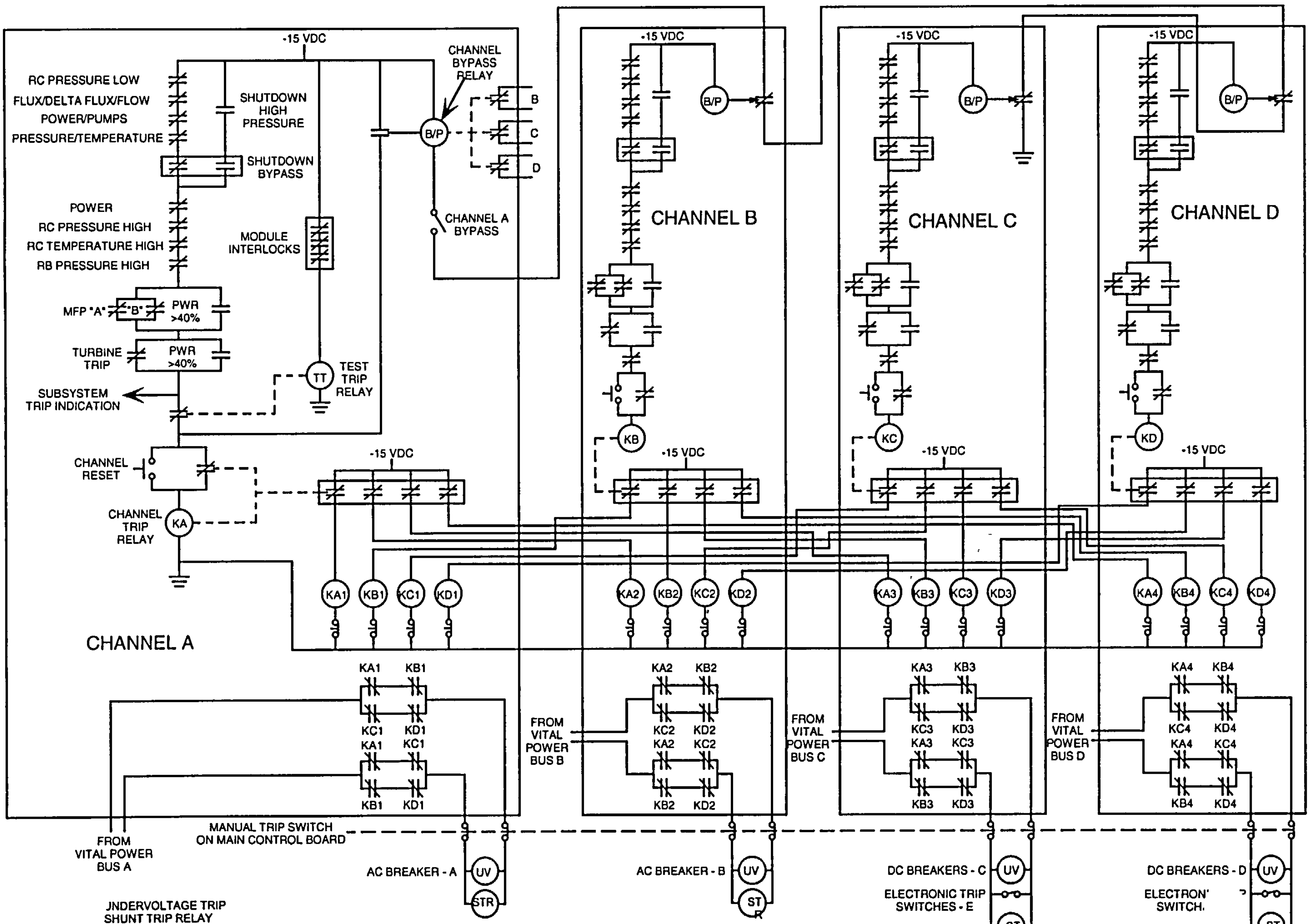


Figure10.1-6 Reactor Protection System Channel Logic

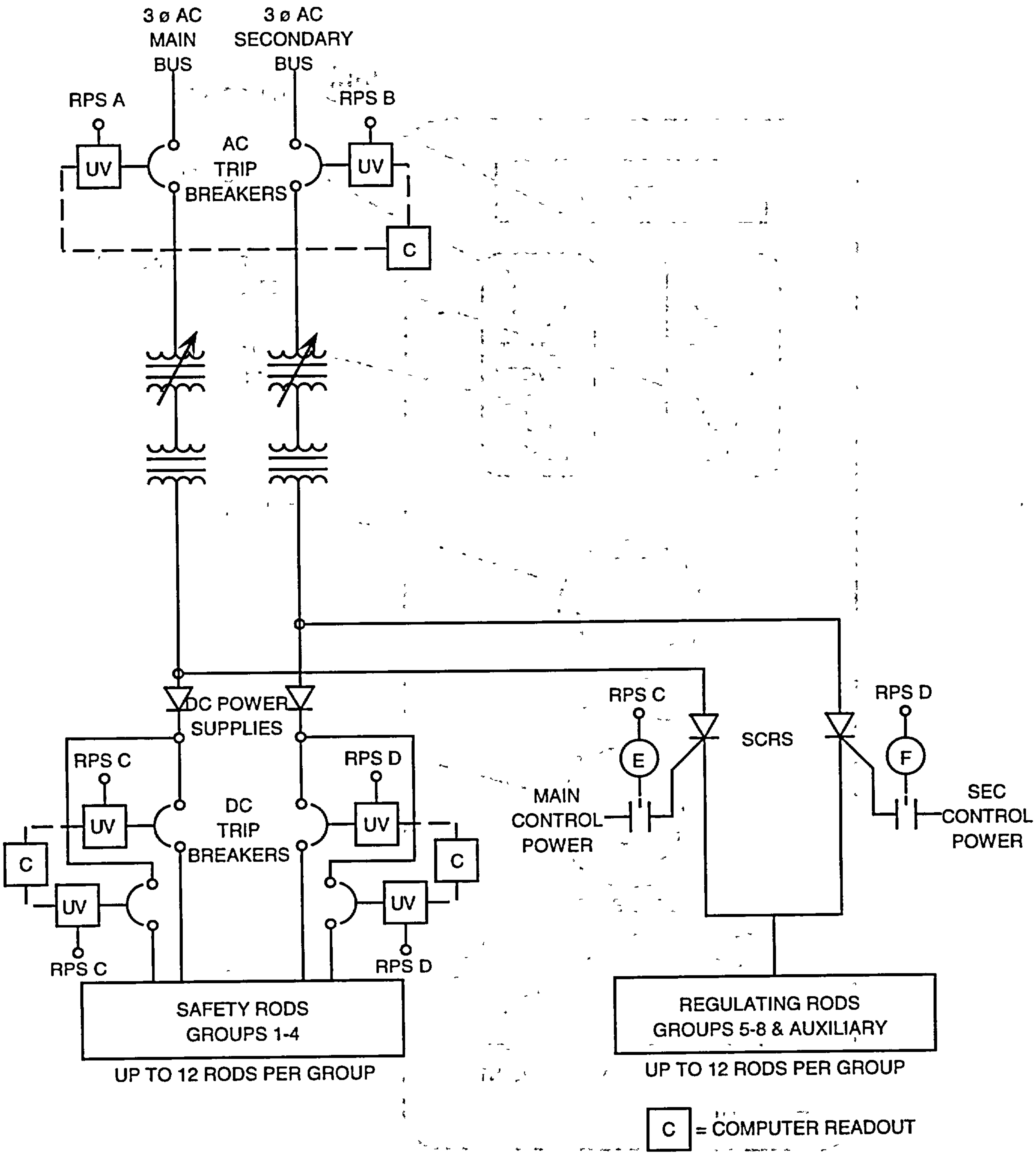


Figure 10.1-7 Reactor Trip Circuit Breakers

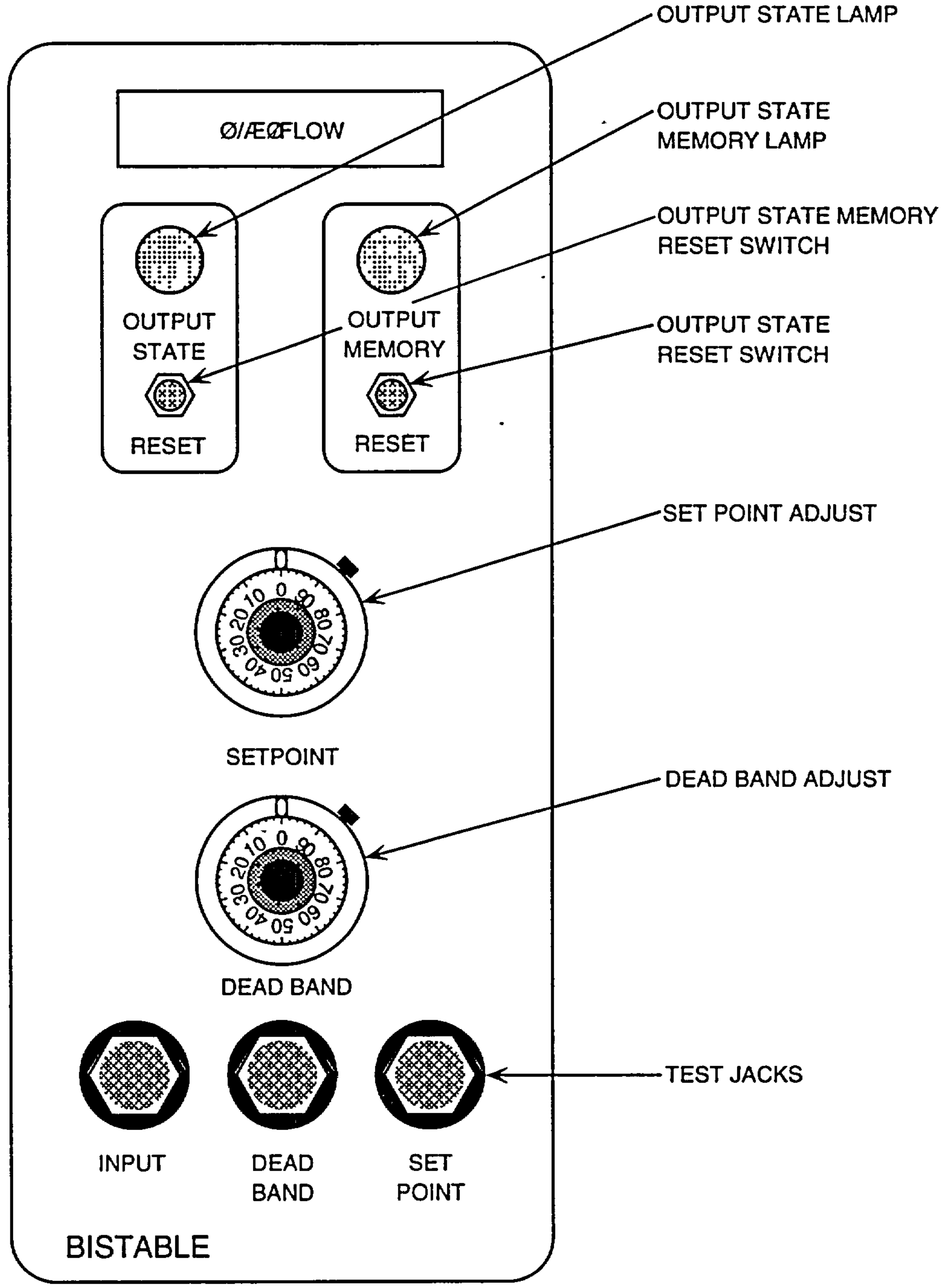


Figure 10.1-8 Bistable Module

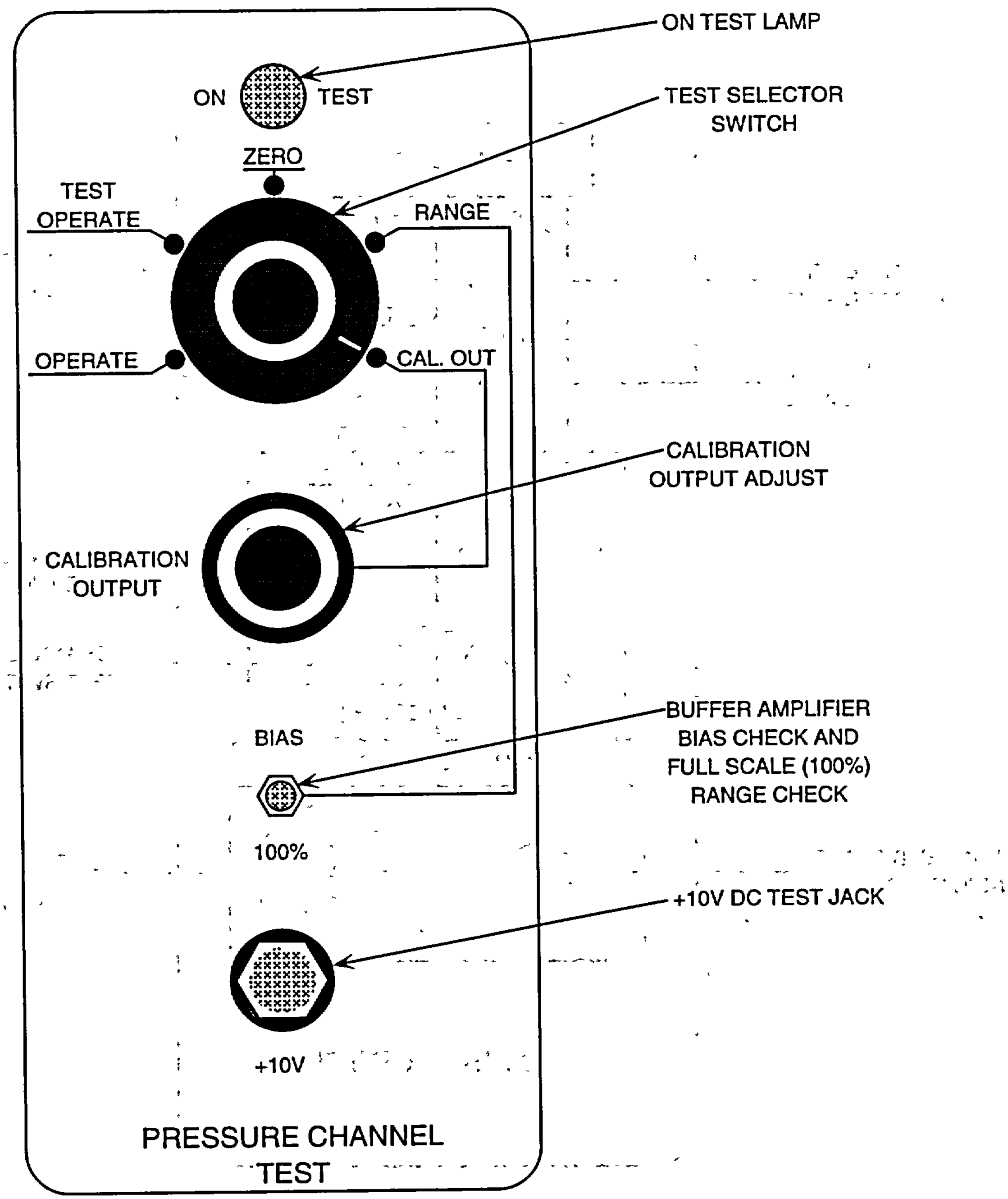


Figure 10.1-9 Channel Test Module

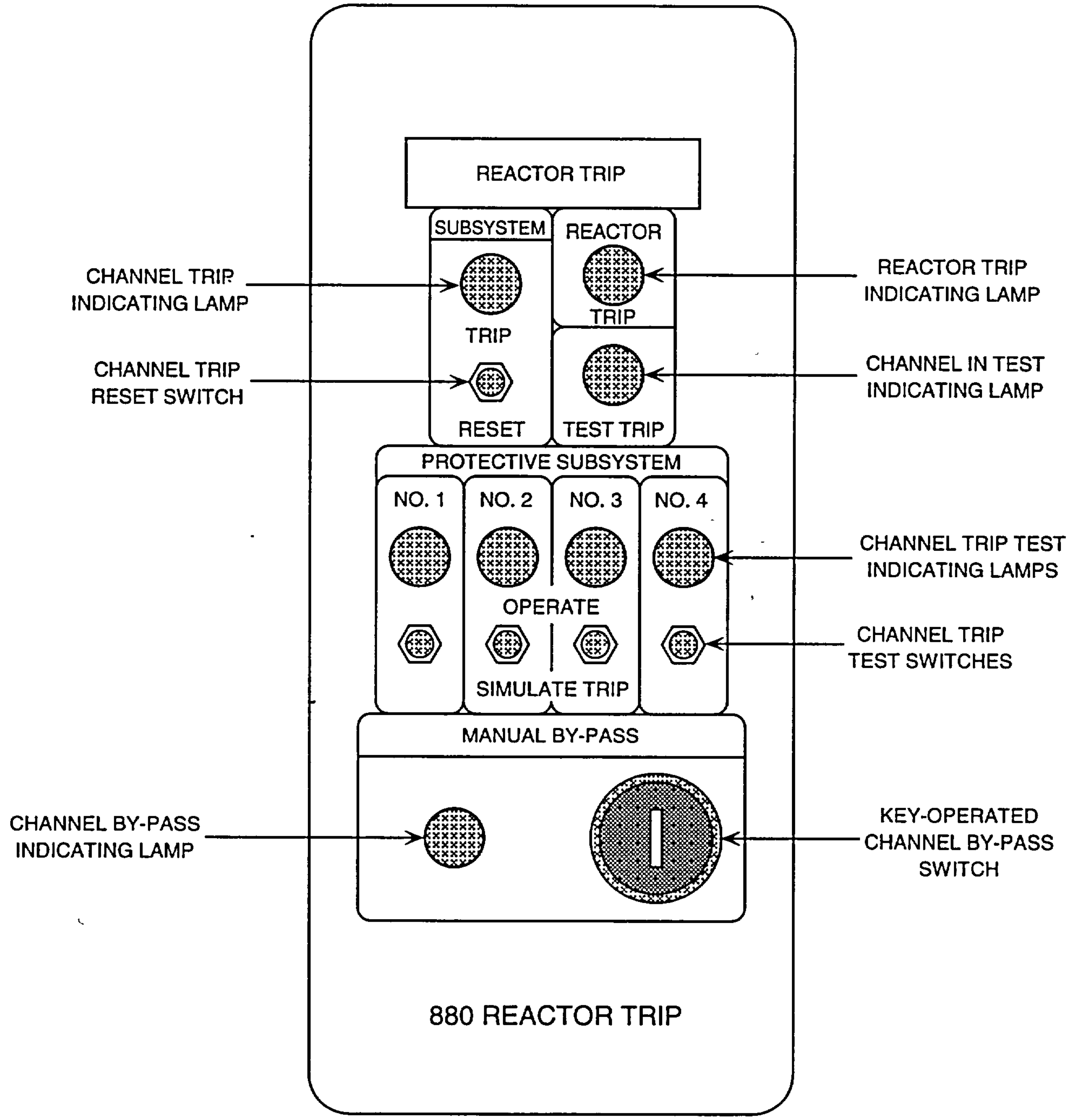
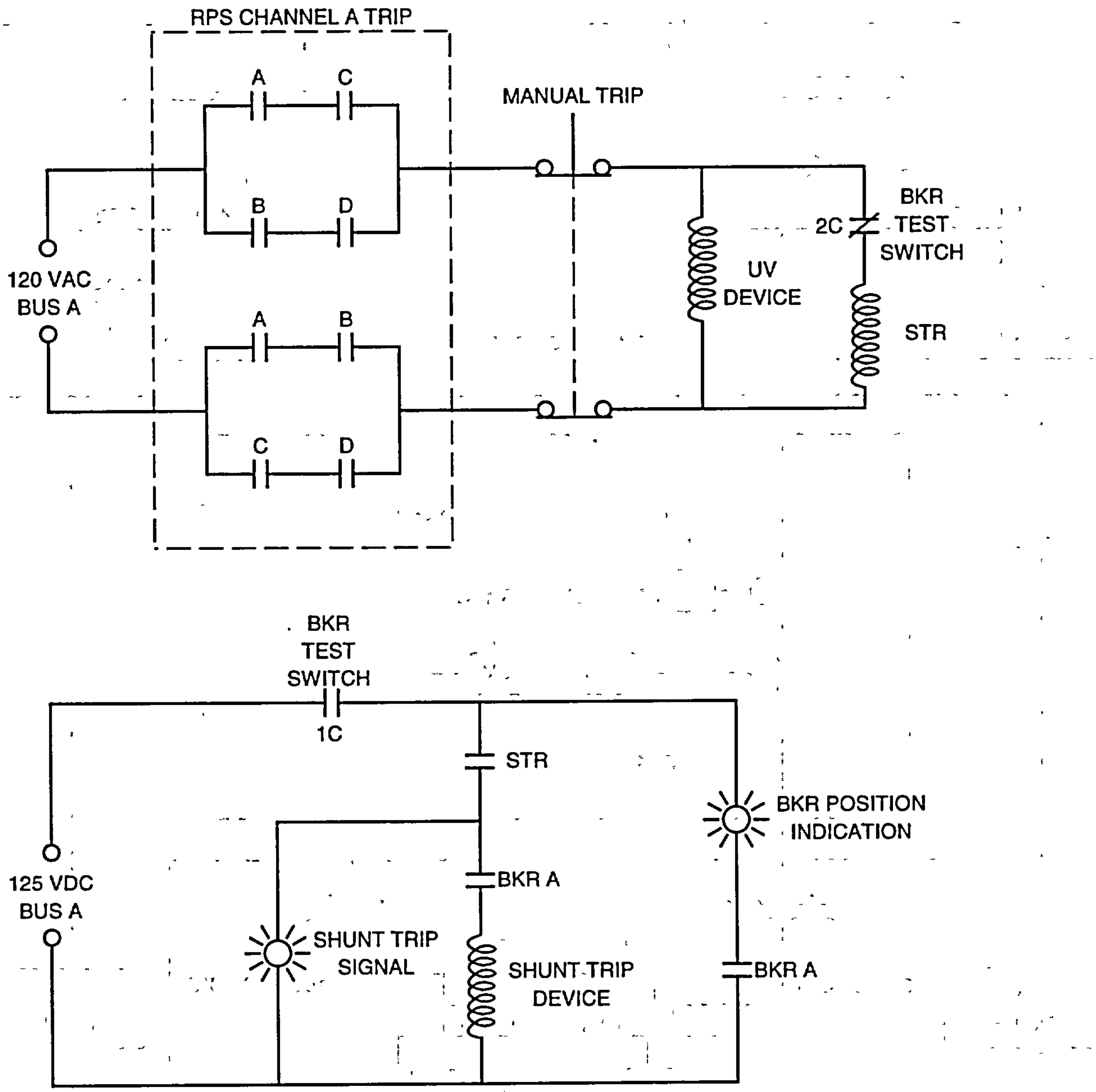


Figure 10.1-10 Reactor Trip Module



SOURCE INTERRUPTION SCHEME

	SHUNT TRIP DEENERGIZE	NORMAL	SHUNT TRIP TEST
1C		X	X
2C	X	X	

CIRCUIT SHOWN IN TRIPPED (DEENERGIZED) CONDITION.

Figure 10.1-11 Shunt Trip Circuitry

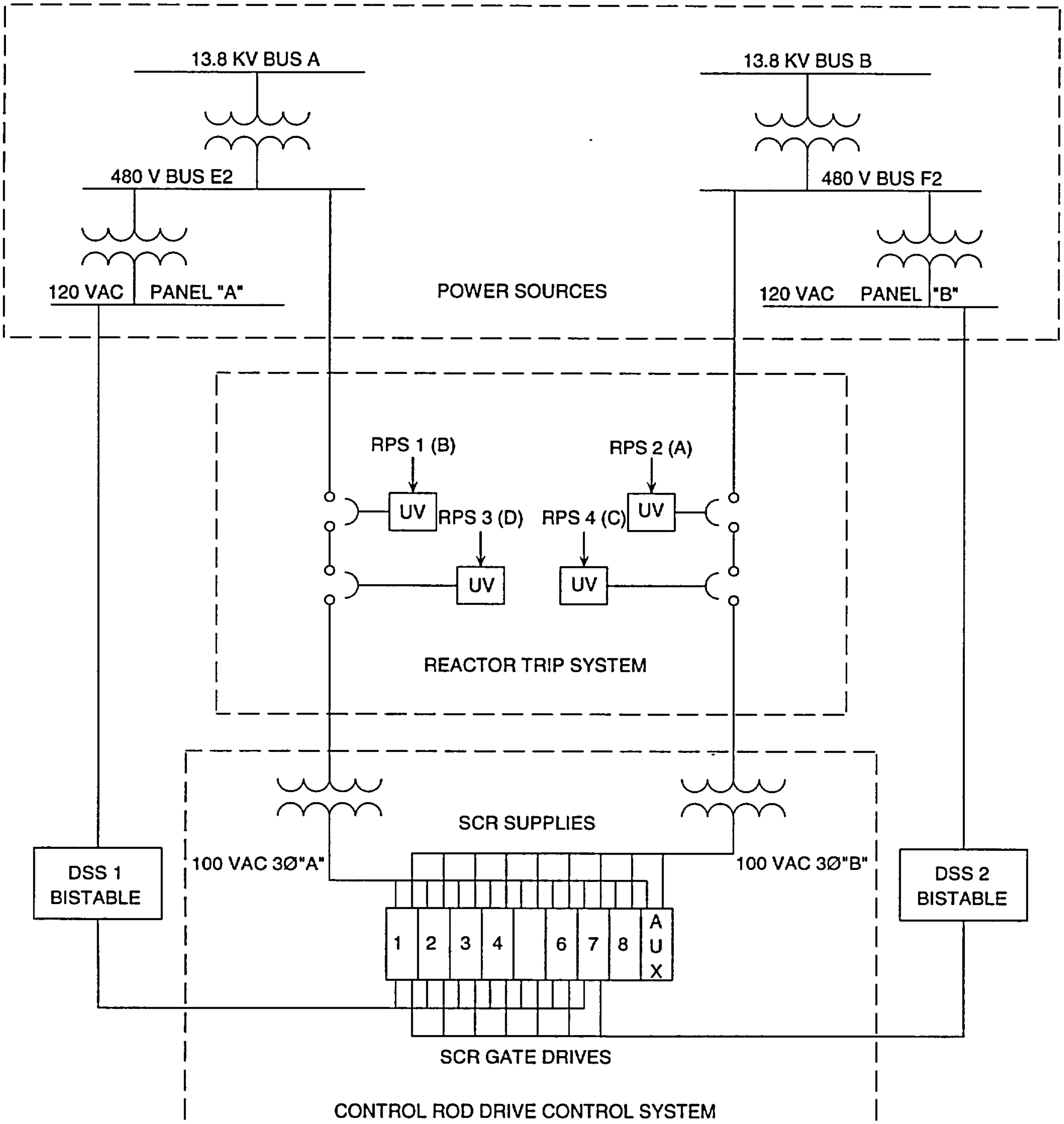


Figure 10.1-12 Backup (Diverse) Scram System (Davis-Besse)

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10.2 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Learning Objectives:

1. List the functions provided by the engineered safety features actuation system (ESFAS).
2. List the ESFAS signals and the accidents that will initiate each.
3. Define the following terms:
   a. Analog subsystem
   b. Digital subsystem
   c. ESFAS channel
   d. Unit control module
4. Describe the sequence of events (flowpath) for an ESFAS signal from the sensor to component actuation, including ESFAS logic.
5. List the systems that are actuated by ESFAS signals.
6. Explain when and how the ESFAS is bypassed.
7. Explain how the control room operator gains equipment control after an ESFAS actuation has occurred.
8. Describe the status of the ESFAS following the loss of one train of the vital 120-Vac distribution system.

10.2.1 Introduction

The engineered safety features actuation system is designed to actuate emergency core cooling system equipment, reactor building isolation valves, and reactor building pressure control equipment. The components are activated by the ESFAS in the event of a loss-of-coolant accident, steamline break, or feedwater line break, and perform the following functions:

1. Minimize fuel cladding damage,
2. Provide reactor building isolation,
3. Decrease reactor building pressure,
4. Remove fission products from the reactor building atmosphere, and
5. Provide long-term core cooling.

10.2.2 System Description

To accomplish the required functions, the ESFAS is supplied with various pressure and level transmitter inputs that are used as indications of accident conditions. By sensing reactor coolant pressure, reactor building pressure, and BWST level, ESFAS can actuate emergency equipment that will mitigate the consequences of primary or secondary system line breaks.

If a rupture occurs in the reactor coolant system (RCS), reactor coolant pressure will decrease and reactor building pressure will increase. Also, if a main steamline breaks inside the reactor building, reactor coolant pressure will decrease because of overcooling of the RCS, and reactor building pressure will increase. A steamline break outside the reactor building will also produce an RCS pressure decrease, but this break will not cause an increase in reactor building pressure. If the feedwater header breaks inside the reactor building, the hot feedwater will flash to steam. The flashing of feedwater coupled with the blowdown of the steam generator will increase reactor building pressure. By comparing the changes in pressures with predetermined setpoints, the ESFAS can actuate the necessary emergency systems.

The required comparison of input pressures with predetermined setpoints is performed in three separate, redundant analog ESFAS subsystems (Figure 10.2-1). If any two of these three subsystems sense that an input pressure parameter has reached its setpoint, two redundant digital subsystems will be activated by the analog subsystems. The digital subsystems provide start-stop/open-close signals to the redundant engineered safety features (ESF) equipment. The ESF equipment is divided almost equally between the digital cabinets so that in the event of a failure of a digital subsystem, the operable digital subsystem will initiate the operation of sufficient equipment to mitigate the effects of the accident.

The basic actuation scheme of the ESFAS is that when pressures in two out of three analog subsystems reach their setpoint, they deenergize relays that, in turn, energize the digital subsystems. Table 10.2-1 shows a listing of the analog inputs and setpoints, the digital subsystem channel divisions, and the emergency systems that are actuated by the redundant (A and B) digital subsystems.

10.2.3 Analog Inputs

10.2.3.1 Reactor Coolant System Pressure

The reactor coolant pressure inputs to the ESFAS originate with pressure transmitters that sense RCS hot-leg pressure. Three wide-range (0 to 2500 psig) transmitters (two sense loop A pressure, and one senses loop B pressure) provide the required inputs (one transmitter for each ESFAS analog subsystem).

10.2.3.2 Reactor Building Pressure

A separate reactor building pressure transmitter with a range of -5 to +35 psig provides an input to each ESFAS analog subsystem.

10.2.3.3 Borated Water Storage Tank Level

Each individual analog subsystem receives a 0 to 55-feet borated water storage tank (BWST) level input from a separate level transmitter.

10.2.4 Analog Subsystems

There are three redundant analog subsystems (Figure 10.2-2). A single typical analog subsystem is discussed in the following section.

10.2.4.1 Input Signal Processing

Each of the transmitters associated with the analog subassembly supplies its input through a buffer amplifier. This buffer converts the 4 to 20-ma transmitter signal to a 0 to 10-vdc signal. The output of the buffer is supplied to a meter that locally displays the value of the parameter at the ESF cabinets and to bistable(s) for ESF actuation.

10.2.4.2 Bistables

Each analog subsystem bistable receives two inputs, the actual value of the parameter and the predetermined setpoint, and compares the two. If the actual parameter reaches the setpoint, the bistable will deenergize. Bistable deenergization is indicative of the need for emergency system actuation. The outputs of the high-high reactor building (RB) pressure bistables and the low BWST level bistable are connected directly to logic buffers. The outputs of the low RCS pressure and the high RB pressure bistables are connected to "OR" gates.

10.2.4.3 Emergency Core Cooling Initiation

The emergency core cooling initiation (ECCI) "OR" gate receives inputs from the low RCS pressure bistable and the high RB pressure bistable. The loss of either of the two inputs (caused by bistable deenergization) will cause a loss of output of the ECCI "OR" gate, which will result in a subsystem trip. If at least two out of three analog subsystems trip, the digital subsystems will actuate the high and low pressure injection systems.

10.2.4.4 Reactor Building Isolation

Reactor building isolation is initiated from the high RB pressure bistable or the low RCS pressure bistable. If either of these inputs deenergize, the RB isolation "OR" gate will transmit an actuation signal to the digital subsytems' logic gates.

10.2.4.5 RB Spray

Reactor building spray is initiated from two high-high (>25 psig) bistables. Two bistables are used to minimize the possibility of inadvertent spray addition to the RB atmosphere.

10.2.4.6 Sump Recirculation

Sump recirculation is initiated by low BWST level. The purpose of this signal is to provide automatic alignment of long-term core cooling.

10.2.5 Digital Subsystems

Each of two separate, redundant digital subsystems receives inputs from the three redundant analog subsystems. When the digital subsystems sense that any two of the three analog subsystems have deenergized, the digital subsystems will energize to activate engineered safety features equipment.

10.2.5.1 Two-out-of-Three Digital Logic

The outputs of the analog subassemblies are connected to the 2-out-of-3 logic gates in the digital subassemblies. These logic gates represent all possible 2-out-of-3 combinations (AB, AC, BC). The output of each logic gate is connected to the unit control modules associated with the digital channel. If any two out of three analog subsystems deenergize, the associated 2-out-of-3 logic gate will energize and actuate the unit control modules.

10.2.5.2 Unit Control Modules

The unit control modules serve as the interface devices between the ESFAS and the emergency equipment. There is a unit control module installed for each piece of emergency equipment required to be operated. When the unit control modules are energized, relay action starts the required pumps and opens or closes valves to align the emergency systems for the accident condition. The actuation of equipment by the unit control module bypasses the normal control switch (start/stop, open/close) for the emergency equipment. Manual and automatic pushbuttons are provided for each unit control module and are discussed in Section 10.2.6.2.

10.2.6 Manual Initiation and Bypass

10.2.6.1 Manual Initiation

The operator can manually initiate ESFAS if he deems it necessary or if a failure of the analog subsystems occurs. A manual initiation switch (Figure 10.2-2) is installed for each digital channel and is connected to a digital logic "OR" gate. When the manual switch is depressed, it will cause the "OR" gate to energize the unit control modules. The action of the unit control modules is the same as that initiated by an automatic signal.

A manual reset switch (not shown) is also installed for each digital channel. This switch allows the resetting of the digital "OR" gate after manual initiation. Manual resetting of the system can be accomplished only if no automatic actuation signal is present. The manual reset switch will not override the automatic actuation caused by the analog subsystems, reposition any valves, or stop any pumps.

10.2.6.2 Unit Control Module Operation

The manual and automatic pushbuttons (Figure 10.2-3) associated with a unit control module allow (1) manual control of the particular emergency system component controlled by that unit control module, (2) the return of the emergency equipment to automatic control, and (3) the testing of emergency system component response to an ESFAS signal.

If an ESFAS signal has actuated the emergency systems, the operator can regain control of an individual component by first depressing the manual pushbutton of the associated unit control module and then changing the condition (i.e., on or off, open or closed) of the component with its normal control switch. The manual and automatic pushbuttons only affect the unit control module logic. Therefore, only the associated components are affected when the manual pushbutton is depressed. The operator can return the components to their accident positions by depressing the automatic pushbutton of the appropriate unit control module.

The final function of the manual and automatic pushbuttons is component testing. During certain portions of ESFAS testing, power to the internal logic of the unit control module is provided by an energized test bus. In this situation, an emergency system component can be made to assume its accident position by depressing the manual pushbutton. The test would be ended by depressing the automatic pushbutton.

10.2.6.3 Bypass Circuits

During normal plant cooldowns, RCS temperature and pressure are reduced. To prevent inadvertent ESFAS actuation, low RCS pressure actuation can be bypassed (Figure 10.2-2). When RCS pressure is less than 1850 psig, as sensed by the RCS pressure bypass bistables, the operator is allowed to bypass the RCS pressure inputs to the emergency core cooling initiation and RB isolation "OR" gates. As the plant is heated up and RCS pressure is increased to above 1850 psig, the bypass is automatically removed.

10.2.7 System Operations

10.2.7.1 Decay Heat Removal Valve Interlocks

The reactor coolant system pressure transmitters are connected to bistables (not shown) that provide interlocks for valve positions in the decay heat removal (DHR) system. The DHR suction isolation valves are interlocked closed on high RCS pressure to prevent exceeding the design pressure of the DHR system. The DHR suction line originates from the loop "A" hot leg and then splits into two separate 14-inch pipes. Each of these pipes contains two motor-operated isolation valves. One valve in each suction pipe is automatically closed by ESFAS, and the other valve is closed by the essential controls and instrumentation system. The DHR valve interlock is supplied from analog subsystems A and B.

10.2.7.2 Sump Recirculation Channel Interlocks

During plant cooldowns, the suctions for the low-pressure injection system are aligned to the A RCS hot leg. During this time, the automatic switchover to the reactor building sump for long-term core cooling could damage the decay heat removal pumps. To prevent the automatic switchover, the sump recirculation ESFAS channels (5A and 5B) are interlocked with channels 1A and 1B. Since bypass is initiated during cooldown, channels 1A and 1B cannot actuate, and automatic switchover of the low-pressure injection suctions to the reactor building sump is prevented. This feature is of particular importance when the BWST contents are pumped to the refueling canal during refueling.

10.2.7.3 Loss of One Vital AC Power Source

The ESFAS receives power from 120-vac class 1E vital busses. However, one analog (A) and one digital subsystem (A) receive power from the same vital bus. The ability of the system to function during a loss of this power source is discussed below.

When power is lost to analog subsystem A, all the bistables (Figure 10.2-2) associated with this subsystem will deenergize. Digital subsystem B will receive an analog subsystem A actuation input in each digital channel. Digital subsystem A will be inoperable because it is an energize-to-operate subsystem.

The status of the ESFAS will be as follows:

1. Analog subsystem A bistables are all deenergized, sending actuation signals to digital subsystems A and B.

2. Digital subsystem B actuation logic has been reduced to 1-out-of-2, and the remaining required signal to actuate must originate in analog subsystem B or C.

3. Only the emergency equipment that is controlled by digital subsystem B will automatically actuate if a valid signal is received. However, since the emergency equipment is redundant, only one-half of the emergency equipment is required to actuate to provide protection for any accident. The loss of digital subsystem A does not interfere with the manual starting of emergency equipment by the operator.

10.2.8 PRA Insights

There is a failure probability associated with the ESFAS system. However, the possibility of miscalibration of instrumentation or misreading of instrumentation (human error) outweighs the possibility of hardware failure, according to the ANO1 PRA. The relative importance of the failure of ESFAS to core melt is low, according to generic PWR PRA data. In fact, the system ranks 14th out of 15 systems in order of importance.

10.2.9 Secondary System Protection

If a break occurs in the secondary system, the accident is mitigated by the closure of main steam isolation valves (MSIVs) and main feedwater isolation valves (MFIVs). A break in a steamline upstream of the MSIVs will result in a pressure decrease in one steam generator and closure of the affected steam generator MSIVs and MFIVs when pressure is less than 600 psig (Figure 10.2-4). This action and the operation of the feed-only-good-generator logic of the auxiliary feedwater system, described in chapter 5, will limit the blowdown to one steam generator. A break downstream of the MSIVs, which depressurizes both steam generators, will result in closure of all valves, isolating the break.

Secondary system protection can be bypassed for normal cooldown and depressurization when steam generator pressure is less than 750 psig. Bypass requires manual action by the operator for each steam generator separately, and resets automatically when pressure exceeds 750 psig.

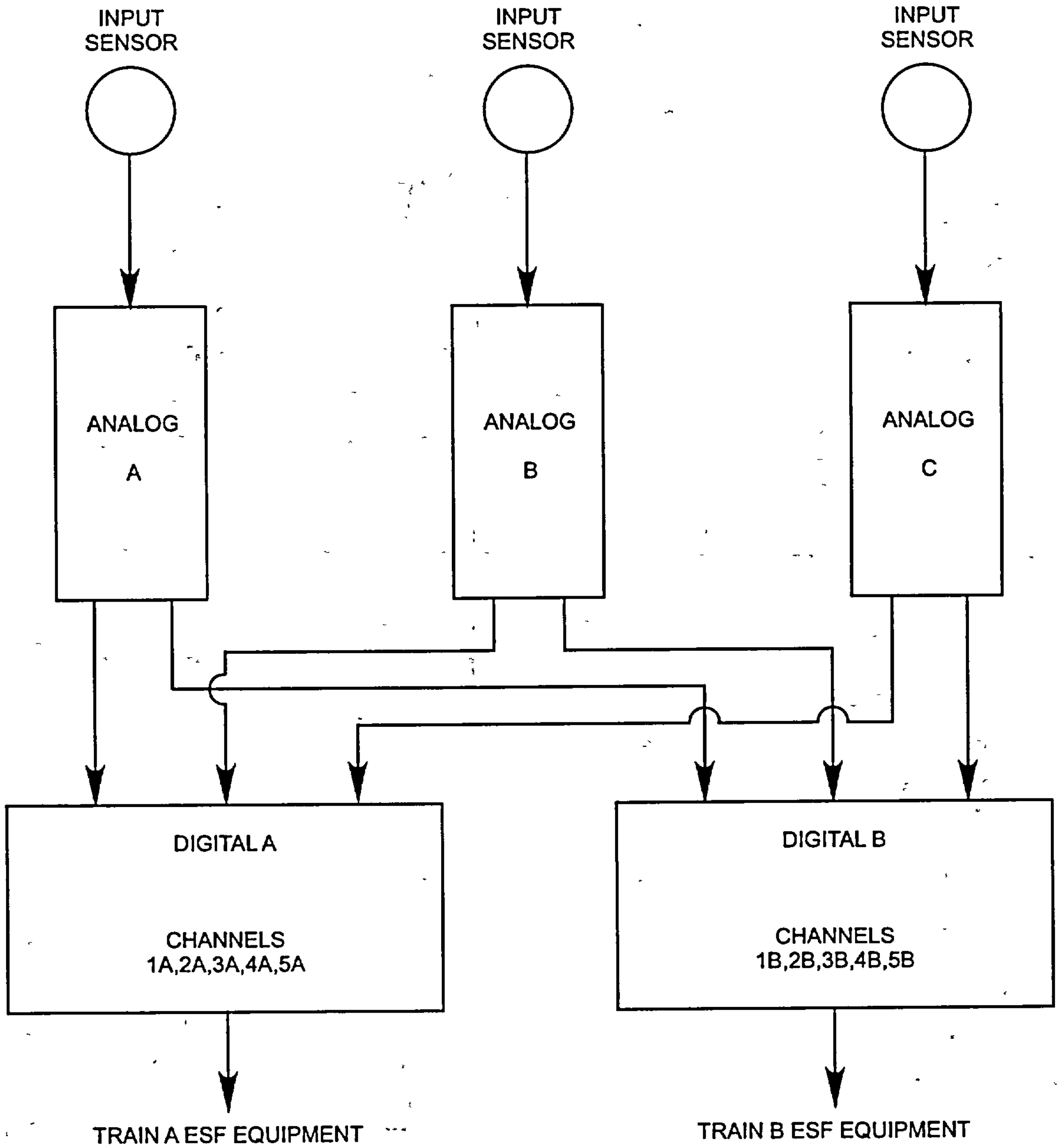
10.2.10 Summary

The engineered safety features actuation system (ESFAS) is designed to aid in the mitigation of primary and secondary system breaks by sensing the abnormal condition and actuating emergency equipment. In addition, the ESFAS provides long-term core cooling during a loss-of-coolant accident by shifting the suctions of the emergency core cooling pumps from the BWST to the reactor building sump.

The ESFAS consists of three separate, redundant analog subsystems, which are deenergized to actuate, and two separate, redundant digital subsystems, which are energized to actuate. The analog subsystems receive inputs of RCS pressure, RB pressure, and BWST level and compare these inputs with predetermined setpoints to ascertain the need for emergency system operation. The digital subsystems receive inputs from the analog subsystems, and if at least 2 out of 3 analog subsystems have reached a setpoint, then actuation of emergency equipment will occur. Each digital subsystem is divided into redundant channels that control different functions. The first channel actuates high-pressure injection and low-pressure injection on low RCS or high RB pressure. The second channel activates RB isolation on low RCS pressure or high RB pressure. The third and fourth digital channels actuate the RB spray header isolation valves and RB spray pumps on high-high RB pressure. The final channel is provided to accomplish the automatic emergency core cooling system suction switchover from the BWST to the RB sump when a low level condition occurs in the BWST.

TABLE 10.2-2 ESFAS ACTUATION SUMMARY

Actuation Signals	Digital Channels	Actuated Systems/Components
Low RCS Pressure (<1600 psig) High RB Pressure (>4 psig)	1A, 1B	High Pressure Injection Low Pressure Injection Makeup System Isolation Auxiliary Feedwater Diesel Generators
Low RCS Pressure (<1600 psig) High RB Pressure (>4 psig)	2A, 2B	All Nonsafety-related RB Penetrations
High-High RB Pressure (>25 psig)	3A, 3B	RB Spray Header Isolation Valves
High-High RB Pressure (>25 psig)	4A, 4B	RB Spray Pumps
Low BWST Level (<5.1 ft)	5A, 5B	LPI Sump Suction Valves RB Spray Sump Suction Valves



CHANNEL	EQUIPMENT
1A, 1B	HPI, LPI, EDGs, AFW
2A, 2B	RB ISOLATION AND COOLING
3A, 3B	RB SPRAY ISOLATION VALVE
4A, 4B	RB SPRAY PUMPS
5A, 5B	SUMP RECIRCULATION

Figure 10.2-1 Engineered Safety Features Actuation System (Block Diagram)

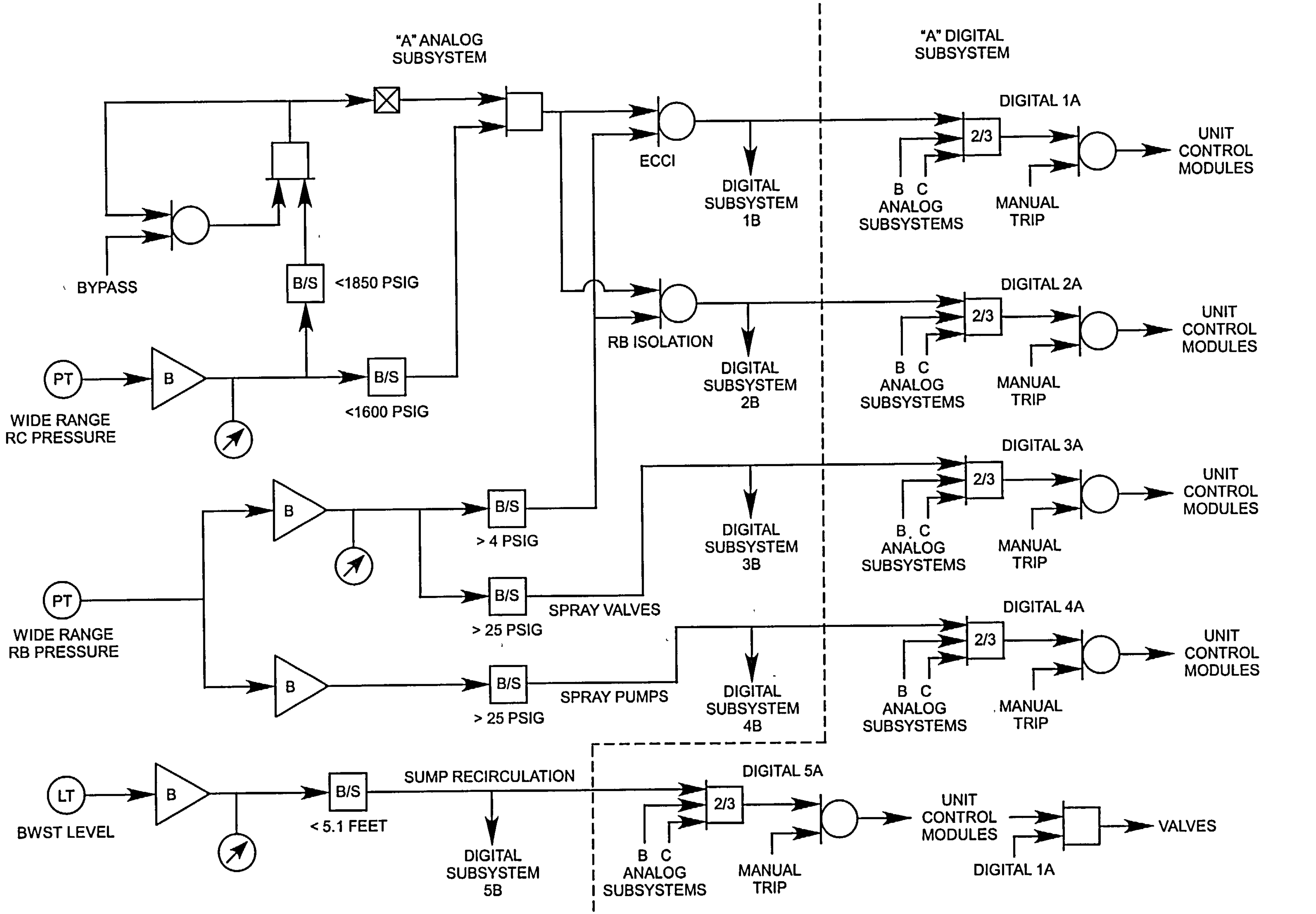


Figure 10.2-2 Engineered Safety Features Actuation System

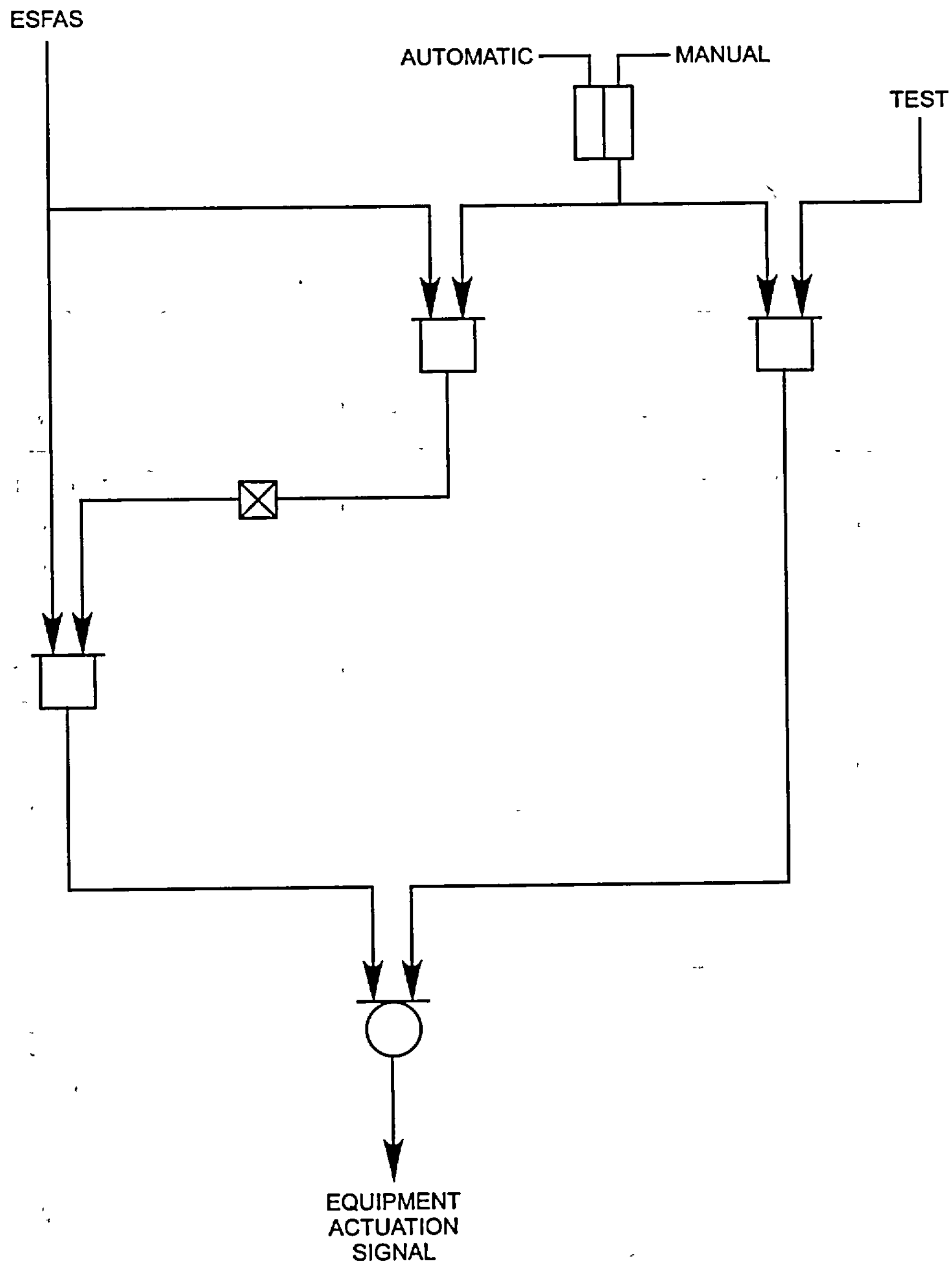


Figure 10.2-3 Unit Control Module Logic

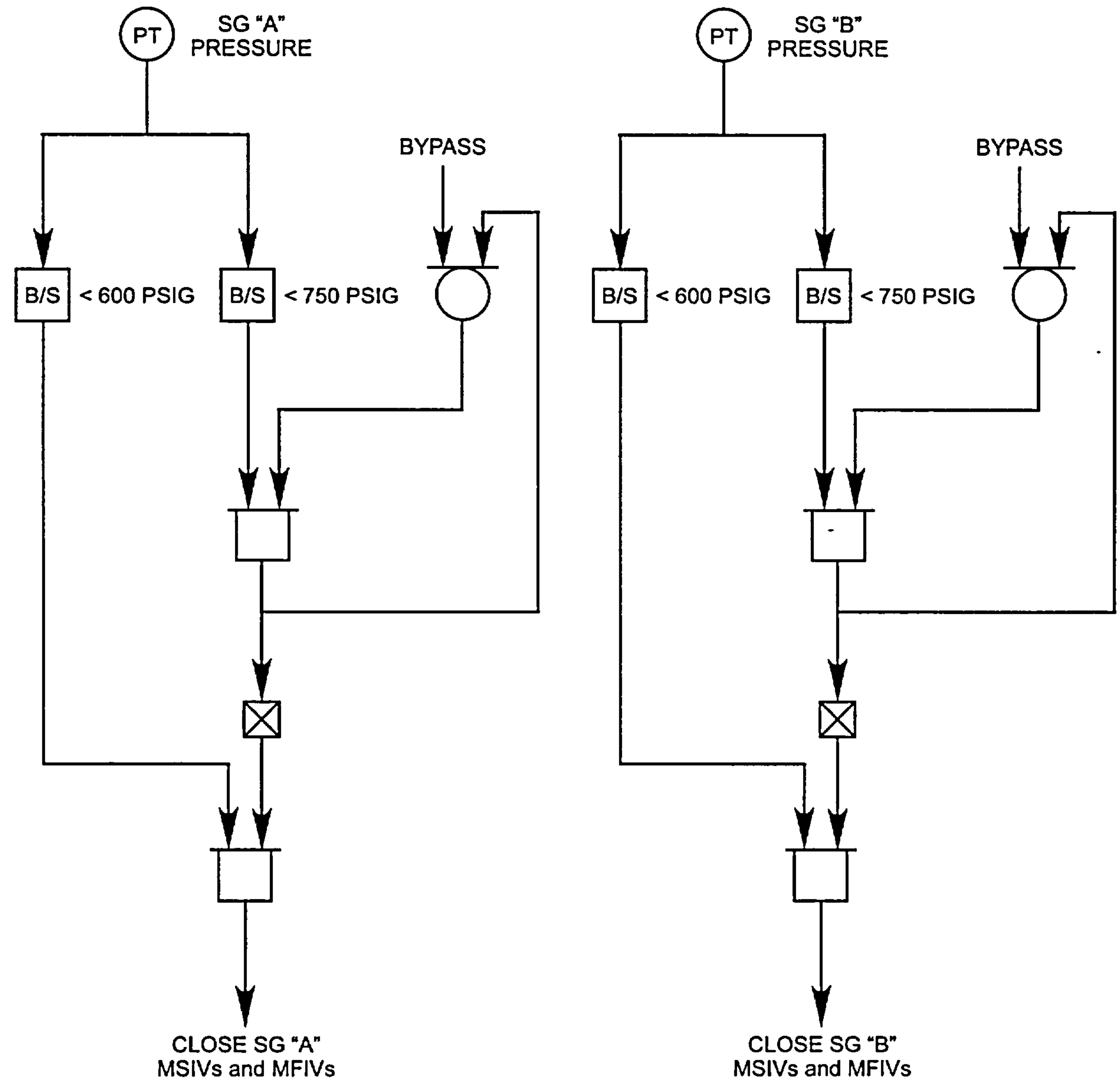


Figure 10.2-4 Secondary Protection System

BABCOCK AND WILCOX
CROSS TRAINING MANUAL

CHAPTER 11 ANO-1 Partial Loss of Flow

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11.0 ANO-1 PARTIAL LOSS OF FLOW

Learning Objectives:

1. Explain the actions of the rapid feedwater reduction (RFR) circuits on the integrated control system and the feedwater system components.
2. Explain the cause of the overcooling of the reactor coolant system.
3. Explain how reverse flow occurred from the reactor coolant system into a cross connect of high pressure injection lines outside the reactor building.
4. State the concern over the reactor coolant flow into the high pressure injection system.

11.1 Introduction

On January 20, 1989, ANO-1 experienced an event which included a partial loss of flow in the reactor coolant system, leakage of reactor coolant through a check valve into a high pressure injection pipe, and a failure of the main feedwater system to decrease flow as designed after the reactor trip. The plant was operating at full power when main generator problems caused a generator trip. The turbine and reactor tripped as designed, but the failure of a bus transfer resulted in loss of power to two of the reactor coolant pumps. This partial loss of flow set up a differential pressure across the high pressure injection connections to the reactor coolant system. The failure of a check valve to reseat caused reactor coolant to flow through a cross connect pipe in the high pressure injection system outside the reactor building. Several failures in the feedwater and related systems allowed overfeeding of one of the steam generators, causing an slight overcooling of the reactor coolant system. A post reactor trip walkdown of the reactor building revealed a small leak in a weld where a drain line connects to a reactor coolant pump suction pipe. A detailed sequence of events is given in the Appendix.

11.2 Main Generator Failure

The turbine trip and subsequent reactor trip were caused by a trip of the main generator. The failure of the generator was a result of a loss of the generator field. An electrical connection on the exciter broke from what appeared to be a stress induced crack, possibly due to the weight of the lead wire and constant low level vibration during operation. The exciter is not a safety-related system.

11.3 Failure of Fast Bus Transfer

After a main generator trip, power to plant loads shift from the unit auxiliary transformer to the startup transformer. Power to the unit auxiliary transformer is supplied by the main generator, while power to the startup transformer is from the offsite power system. There are four non-vital buses that transfer to startup transformers, two of which supply reactor coolant pump motors and two which supply vital buses. One bus that supplies two reactor coolant pump motors failed to fast transfer. A slow transfer did occur, but the pumps had already tripped. This failure did not affect any vital buses. If the transfer had affected a vital bus, the bus would have been isolated and then supplied by a diesel generator. The licensee believes the failure to be related to the reset time on a synchronism check relay.

11.4 Spurious Actuation of EFIC Channels

Two redundant channels of the emergency feedwater initiation and control (EFIC) system actuated spuriously immediately after the turbine trip. The actuation signal was low OTSG level, although the levels were above the setpoint for actuating emergency feedwater. No equipment actually started because the channels that tripped did not satisfy the actuation logic. The actuation was caused by pressure oscillations in the steam lines induced by the closing of turbine stop valves. The time delays built into the system are either too short or did not function properly. If there had been an actuation of emergency feedwater, it would have added to the overcooling problem caused by other failures.

11.5 Main Feedwater System Failures

During normal operations, feedwater flow is controlled by the integrated control system (ICS) using startup control valves (SUCVs) from 0% to 15% power, low load control valves (LLCVs) from 15% to 50% power, and feed pump speed control from 50% to 100% power. Following a reactor trip, the rapid feedwater reduction (RFR) circuits provide signals to the integrated control system (ICS) to close SUCVs and LLCVs and runback the speed of the main feedwater pumps. Figure 11-1 shows the relationships between the RFR circuits, the ICS, and the feedwater pumps and valves.

In the ANO-1 event, the SUCVs and the LLCVs remained open and one of the feedwater pumps did not run back. In addition, the main feedwater block valve associated with the failed pump did not close. These failures all contributed to the overfeeding of an OTSG which caused an overcooling of the reactor coolant system. The failure of the SUCVs and LLCVs was due to a wiring error during installation of the RFR circuits. The ICS operated as designed. The output signals from the ICS and RFR circuits to decrease feedwater pump speed and close the main feedwater block valve were correct. The feedwater pump problem may have been a failure in the pump controller or the turbine steam supply. The main feedwater block valve started to close as designed, but stopped on mechanical overload. A change in the torque switch setting may solve the problem in the future.

11.6 Check Valve Failure

The overcooling caused by the feedwater system malfunctions made the pressurizer level decrease, and the operators manually started high pressure injection. After two minutes, high pressure injection was secured, but the check valve in the "B" injection line did not reseat. Due to the fact that two reactor coolant pumps were tripped and two were running, a differential pressure was created across high pressure injection lines. The "B" and "C" lines are cross connected, and with the "B" reactor coolant pump running and the "C" pump stopped, the check valve in the "B" injection line was needed to stop flow in the cross connect line. The failure of the check valve allowed hot reactor coolant to flow in a high pressure injection cross connect line and back into the reactor coolant system as shown in Figure 11-2. The discovery was made when a fire alarm activated in a penetration area. The "B" and "C" injection lines were found to be hot. This is of concern because the piping in the injection system is rated for reactor coolant system pressure, but it is not rated for reactor coolant system temperature. Analysis has shown that stress limits were exceeded in certain locations in the cross connect line during the event.

11.7 Reactor Coolant System Leakage

During a routine walkdown of the reactor building after the trip, a "pinhole" leak was found. The hole was on the weld of a drain line connected to the reactor coolant system. The leak was probably due to a weld defect and was not related to the event.

11.8 Summary

This event at ANO-1 began with a failure of the main generator which caused a turbine and reactor trip. The failure of a fast transfer to offsite power on one of the non-vital buses resulted in the trip of two reactor coolant pumps. When several feedwater related problems caused a slight cooldown of the reactor coolant system, the operators manually started high pressure injection. After a couple of minutes, high pressure injection was terminated, but one of the check valves did not reseat. With a differential pressure across high pressure injection lines caused by having two reactor coolant pumps running and two stopped, reactor coolant leaked back into a cross connect line in the high pressure injection system outside containment.

APPENDIX - SEQUENCE OF EVENTS

Initial conditions: 100 percent power; normal operating temperature and pressure.

January 20, 1989

20:30 (?)
(Exact time unknown) Perturbations in the form of voltage swings/spikes are observed by the operators on a control room meter that displays the output voltage from the main generator exciter voltage regulator (i.e., generator field voltage). The normal generator field voltage is 50 Vdc. The voltage spikes occur fairly regularly (at approximately four minute intervals) with peaks values of near 90 Vdc at first, and becoming more severe with time until the meter pegged high at 150 Vdc just prior to losing generator field voltage.

21:58:11
The automatic voltage regulator is placed in the off position by the control room operator. Loss of main generator field voltage occurs due to a failed electrical connection on an exciter field winding. This causes a generator lockout via the generator protection circuits (i.e., the generator field breakers and output breakers open, electrically disconnecting the generator).

The main turbine trips on generator lockout.

The reactor trips on main turbine trip via the safety related anticipatory reactor trip (ART) circuits. The plant operators proceeded to bring the unit to hot shutdown conditions.

The power source to nonsafety-related 6.9kV Bus H1 fails to automatically fast transfer from the unit auxiliary transformer (supplied from the main generator) to the startup transformer (supplied from the offsite power system). An automatic fast transfer does occur to provide power to the other nonsafety- related buses, 6.9kV Bus H2 and 4.16 kV Buses A1 and A2. All safety-related buses transfer as designed following the trip.

21:58:15
A trouble alarm is received in the control room on 6.9 kV Bus H1 loss of voltage.

Reactor Coolant Pumps "A" and "C" trip on undervoltage. These pumps are powered from Bus H1.

Two channels of the emergency feedwater initiation and control (EFIC) system spuriously trip upon sensing once through steam generator (OTSG) low level. Actual OTSG level was well above the emergency feedwater initiation setpoint.

The main feedwater (MFW) system startup flow control valves (SUCVs CV-2623 and CV-2673) and low load flow control valves (LLCVs CV-2622 and CV-2672) fail to close as designed following the reactor trip, allowing continued MFW flow paths to each OTSG.

The "B" MFW pump (P1B) fails to runback to minimum speed as designed following the reactor trip.

The "B" MFW block valve (CV-2675) fails to close as designed following the reactor trip. The valve starts to close, but stops when the valve torque switch actuates before the valve closes.

An automatic "slow dead bus transfer" occurs to provide power to 6.9kV Bus H1 from the startup transformer, restoring power to the bus. Reactor Coolant Pumps "A" and "C" remain shutdown.

SEQUENCE OF EVENTS (continued)

21:59:08
The operators manually start high pressure injection (HPI) System Pump P36A to provide additional makeup flow to maintain pressurizer level above the heater cutoff point. Pressurizer level was decreasing due to reactor coolant system cooldown from excessive MFW flow to OTSG "B" and the slight overcooling (reactor coolant temperature dropped about 11F).

21:59:25
OTSG "B" high level alarm at 92 percent is received in the control room.

21:59:38
The "A" MFW isolation valve (CV-2680) and the "B" MFW isolation valve (CV-2630) are manually closed by the operators from the control room.

21:59:40
The "B" MFW main block valve (CV-2675) is manually closed by the operators from the control room

The "B" MFW pump (P1B) runs back to minimum speed on its own.

21:59:44
Level in the "B" OTSG begins decreasing from a high value of 99 percent on the operating range. Level in the "A" OTSG is less than, and paralleling, the level in the "B" OTSG.

The MFW isolation valves are reopened by the operators from the control room.

22:00:25
"B" OTSG level begins increasing from 91 percent on the operating range.

22:01:33
HPI Pump P36A is secured.

"B" OTSG level increases to near 100 percent on the operating range (actual level may have gone slightly offscale above 100 percent).

22:01:40
"B" OTSG level begins decreasing from 100 percent.

22:02:33
The "B" MFW pump is secured, and Motor Operated Valve CV-2827 in the crosstie line between the discharge of the two turbine driven MFW pumps (P1A and P1B) is opened. MFW Pump "A" is now providing MFW flow to both OTSGs via the SUCVs and LLCVs.

22:03:53
The "A" and "B" MFW isolation valves are closed by the operators from the control room in response to the increasing level in the OTSGs.

Control of the SUCVs and the LLCVs for both OTSGs is transferred from automatic control to manual control, and these valves are manually closed by the operators.

SEQUENCE OF EVENTS (continued)

22: (?)
(Exact time unknown) A fire alarm is received in the control room. The alarm is activated from a smoke detector located in the upper north piping penetration room (UNPPR). There is no fire water system flow to the UNPPR which indicates no actual fire in the area. An operator is dispatched to the UNPPR to investigate the cause for the alarm.

22:31
The NRC Operations Center is notified of the reactor trip in accordance with 10 CFR 50.72. The call was initially misclassified by the licensee as a courtesy call instead of a required notification. The call was made by a shift administrative assistant, not an operator.

22:38 (?)
(Exact time unknown) The "A" and "B" MFW isolation valves (and SUCVs) are reopened by the operators.

22:50 (?)
(Exact time unknown) The operator dispatched to the UNPPR reports back to the control room by telephone that the temperature of the "B" and "C" HPI system injection lines, and the crossover line that connects them, is excessively high (more indicative of RCS temperature than the expected temperature of the borated water used for HPI). The smoke detector is believed to have been actuated when tape attached to the HPI piping began to melt and smolder/smoke. It was noted that this event could have gone undetected. The plant operators suspected that the high temperature in the HPI piping was caused by failure of Check Valve MU-34B to reseat after HPI Pump P36A was secured at 22:01:33. Check Valve MU-34B is located inside the reactor containment building. The leakage flow path was in the reverse direction through Check Valve MU-34B and outside the reactor containment building via the "B" HPI injection line, then through the crossover line to the "C" HPI injection line, and back inside the reactor containment building to the RCS. The upstream check valves (MU-1214 and MU-1215 in the "B' and "C" HPI injection lines respectively) performed as designed to prevent further backflow of reactor coolant into the HPI system piping.

22:59:41
An EFIC system initiation of emergency feedwater (EFW) occurs upon sensing low level in the "B" OTSG. The operators were aware that OTSG levels were decreasing, and were beginning to increase MFW flow at the time of the EFIC system initiation of EFW.

23:00:00
EFW is secured. Very little, if any, EFW system flow was injected into the OTSGs.

23:05 (?)
(Exact time unknown) Auxiliary Feedwater Pump P75 (motor driven) is manually started by the operators from the control room.

23:15 (?)
(Exact time unknown) The "A" MFW pump is secured.

January 21, 1989

1:00 (?)
(Exact time unknown) The oncoming shift waste control operator is dispatched to check the piping in the UNPPR but because of confusion he missed the hot HPI crossover piping. He erroneously reported to the control room that the pipe appeared to be cooling down.

SEQUENCE OF EVENTS (continued)

2:02
The NRC Operations Center is notified of the EFIC system initiation of EFW in accordance with 10 CFR 50.72. This notification was made by the unit shift supervisor.
3:00 (?)
(Exact time unknown) The waste control operator is again dispatched to the UNPPR with better instructions and he correctly determines that the HPI crossover piping is still hot.

3:53
Reactor Coolant Pumps "A" and "C" are restarted. It appears that restarting the pumps causes Check Valve MU-34B to reseat and/or removed the differential pressure which was driving the backflow, stopping the RCS backleakage into the HPI system piping. The waste control operator confirms that the piping was cooling off at this time.

5:00
A routine post reactor trip walkdown of the reactor containment building identifies possible reactor coolant system leakage.

12:56
The leakage is confirmed to be from an elbow weld in a 1 1/2-inch drain line off the "B" reactor coolant pump suction line. The leakage rate is believed to be small (approximately 10 to 20 ml per minute). An Unusual Event (UE) is declared by the licensee due to unisolable RCS pressure boundary leakage. (T.S. 3.1.6.3 requires cooldown to begin within 24 hours of identifying the leakage.)
13:06
Operators begin the process of taking the reactor to a cold shutdown condition.

13:10
The NRC Operations Center is notified of the declaration of an UE in accordance with 10 CFR 50.72. This notification is made by the shift administrative assistant.

January 22, 1989

17:30
The reactor is at cold shutdown, and the UE is terminated.

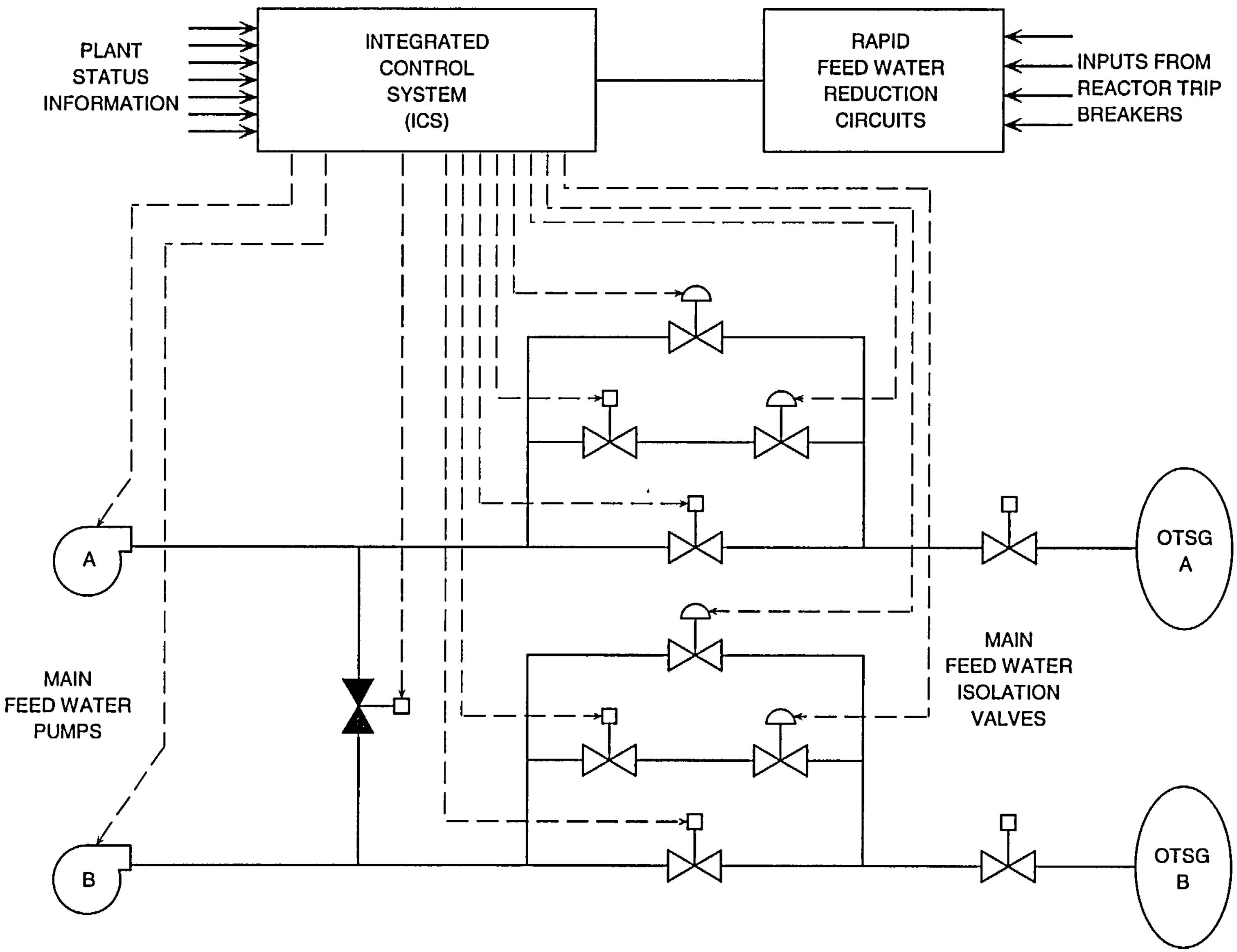

Figure 11-1 Rapid Feedwater Reduction Circuits Interface with ICS and Main Feedwater System

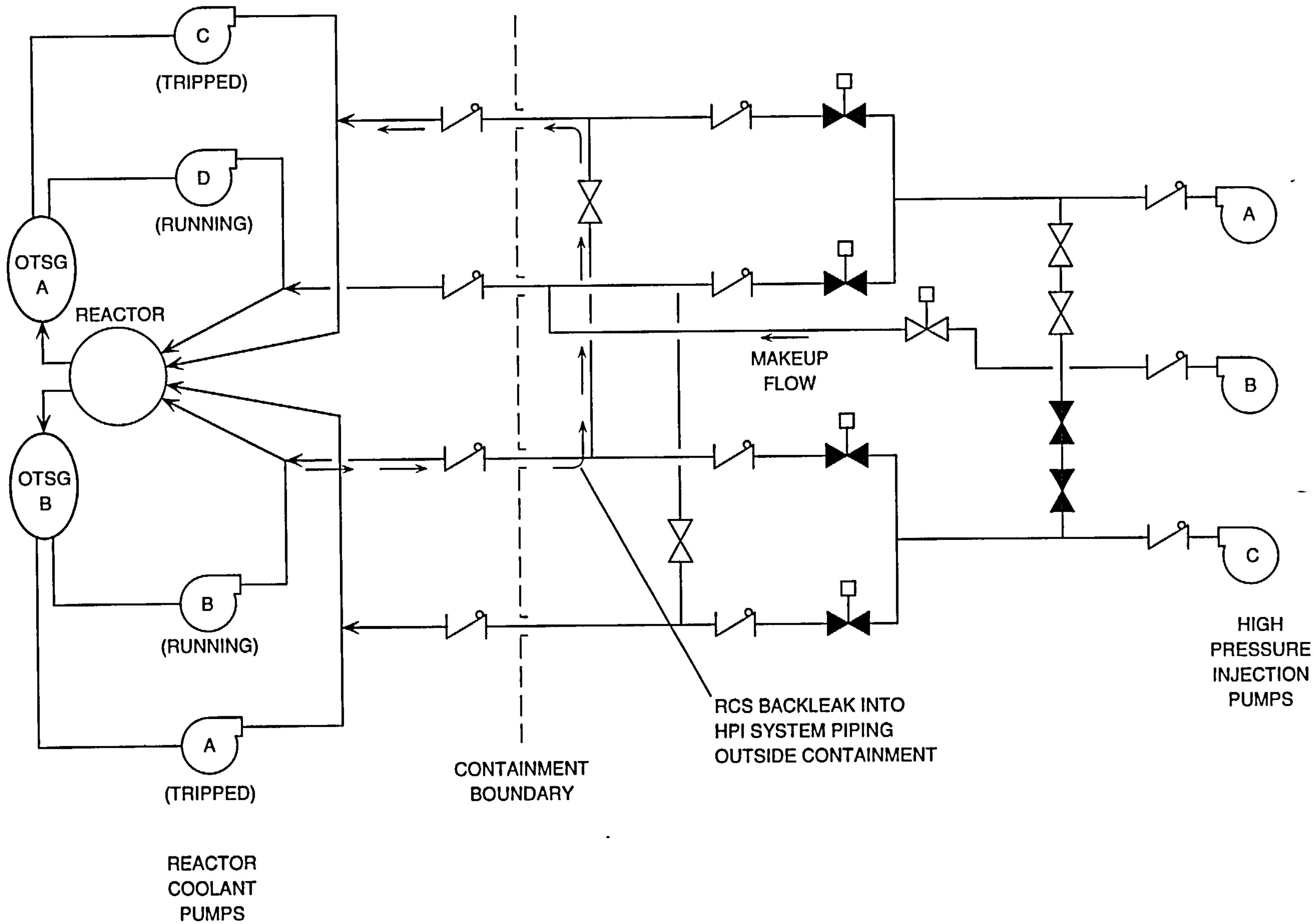

Figure 11-2 High Pressure Injection System

BABCOCK AND WILCOX
CROSS TRAINING MANUAL

CHAPTER 12 OTSG Tube Fouling and Cleaning

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12.0 ONCE-THROUGH STEAM GENERATOR TUBE FOULING AND CLEANING

Learning Objectives:

1. List and discuss the causes of tube fouling in the once-through steam generators.

2. Describe what effects tube fouling has had on normal plant operations.

3. State the five methods used to reduce the amount of tube fouling in the steam generators.

4. Describe the effect each method listed in (3) has had on reducing the operating levels of the steam generators.

12.1 Introduction

Babcock and Wilcox (B&W) nuclear steam supply system once-through steam generators (OTSGs) have experienced secondary side fouling, which has caused operation with high operating range levels and power output limitations. These high levels have made the affected plants susceptible to steam generator overfill events and have contributed to plant trips due to minor and moderate feedwater overfeeding. The degree of fouling and the subsequent limitation of power have been totally plant dependent and seems to be a function of the secondary side chemical controls. Metal oxide deposition on the lower tube support plates appears to be the cause of the increasing secondary side steam generator level.

Several methods have been tried to clean the secondary side of the steam generators in order to reduce the metal oxide content. These methods include; pressure fluctuations, water lancing, water slap and chemical cleaning. At present, chemical cleaning has produced the best results.

12.2 Tube Fouling

The tube fouling is believed to be caused by the deposition of metal oxides in the boiling region of the once-through steam generator. These metal oxides are introduced into the steam generator principally via the main feedwater system. The magnitude of the metal oxides introduction is a function of the oxygen content of the feedwater, feedwater pH, overall water chemistry and operation of the secondary side heater drain systems. Once introduced into the steam generator, the metal oxides can deposit either on the tubes or other surfaces, including directly in the broached holes in the tube support plates, Figure 12-1. The material deposited directly in the broached holes will act to reduce the water/steam flow area and thereby directly increase the steam generator pressure drop. The material deposited directly on the tubes, after building up to a sufficient thickness and being subjected to normal thermal cycles (a plant shutdown, for example), can spall from the tubes in the form of loose flakes. These flakes can be suspended on the underside of the of the support plate during operation, also blocking water and steam flow passages and increasing the secondary side pressure drop. With sufficient secondary side water/steam pressure drop, the water level in the OTSG downcomer increases to compensate until such time as the level reaches a minimum level below the feedwater nozzles. If allowed to continue higher, feedwater heating would be severely reduced and level instabilities could occur.

12.3 Plant Experiences

12.3.1 Three Mile Island Unit 1

The first time a power limitation was observed was late 1985. Subsequently, as a part of the Power Escalation Test Program, a turbine trip, reactor trip was performed. When the plant was restarted, the steam generator level was low enough to achieve full power operation. The second occurrence of a power limitation was early in 1987, at which time the plant was limited to about 83% power. While the power level limitation was observed, GPU evaluated several options available to determine if short term corrective action could be taken. Introduction of minor pressure fluctuations through turbine throttle/bypass valve operation and planned load reductions were performed without any impact on operating levels in the generators. A planned shutdown from a manual turbine trip was performed. The subsequent restart achieved 100% power with adequate margin in steam generator levels.

In the long term, GPU was convinced that the only technical viable solution to the generator fouling problem was to continue maintenance of high quality water chemistry coupled with periodic, but infrequent, chemical cleaning of the steam generators. Up until this time no once-through steam generator had been chemically cleaned.

12.3.2 Arkansas Nuclear One Unit 1

Since the beginning of cycle 3 operation (Spring of 1978) an anomaly in the "A" once-through steam generator secondary side pressure drop was noticed. A significant difference was noted between the "A" and "B" steam generators. While the "B" generator had remained relatively constant, the pressure drop in "A" had continued to increase (Figure 12-2). The overall trend showed that the difference began to increase exponentially. It appeared that the power levels would be limited if the trend continued. Starting in January 1981, the ANO-1 power was steadily decreased in order to maintain the level in the "A" steam generator. Prior to the shutdown in April 1982, power was limited to 83% (Figure 12-3).

AP&L had determined that the increase in operating level was caused by increased flow resistance at the 5th and 6th tube bundle support plates. AP&L believed that the buildup of debris in the "A" OTSG was caused by contaminants from the turbine moisture separators drain system, the condensate polishers, and the drainage from the feedwater heater drain tank. Up until this time these drain system returns were preferentially sent to the A OTSG feedline.

During the April 82 outage, AP&L replaced the existing main feedwater nozzles with inconel nozzles because the holes in the existing nozzles had eroded. Also, the OTSG orifice plates (located in the lower section of the downcomer region to ensure dynamic stability of the recirculated flow) were opened. Confirmation of the debris buildup was accomplished by fiberscope examination of the tube bundle area, where representative deposits were expected, and by removal of deposit samples from the area for chemical analysis. During the January 81 outage a hole was drilled through the shell and shroud at the elevation of the 5th and 6th tube support plates. Special tooling was used to permit visual examination and sample retrieval. Based on the sample results, chemical cleaning was considered as a solution to the fouling problem. During the outage the 5th tube support plate was water lanced to remove the debris. Additionally, an attempt was made to loosen the debris by controlled boil-off of the steam generator. Neither method was entirely effective in reducing the downcomer level.

12.3.3 Crystal River Unit 3

As can be seen from Figure 12-4, the operating levels in the once-through steam generators at Crystal River Unit 3 (CR3) have been steadily increasing since 1977. The most dramatic increases have been seen since 1984. In July 1984, CR3 began limiting the maximum power generation due to the increasing downcomer levels. This decrease is shown on Figure 12-5. Similar to the other utilities discussed, the increase in downcomer level was attributed to increased flow resistance caused by fouling in the lower parts of the steam generator. The fouling took on two forms; a restrictive type blocking of the broach holes within the tube support plates and a coating that built up on the tubes. Although the buildup on the tubes did help restrict flow, it had little effect on the heat transfer capabilities of the steam generator. Samples taken from the generator indicated the buildup to be approximately 95% magnetite (Fe_3O_4). The following table shows the amount and location of the fouling in the steam generators:

Table 12-1 Crystal River 3 Steam Generator Fouling

Tube support plate	Average % broach blockage
6	5
5	30
4	70
3	20
1	5

Notes:
1. Lower tube sheet sludge pile average height - 1.5"
2. SG tubes covered with a 5-10 mil thick layer of black magnetite.

Five sources of fouling were identified:

1. Corrosion products generated on the surfaces of feedwater piping and components.
2. Makeup water (Silica, calcium, and magnesium compounds).
3. Dissolved and suspended particles from condenser cooling water in-leakage.
4. Resin throw from condensate polishing units.
5. Impurities left behind in the system after performing maintenance on the system.

The major source of the fouling was considered to come from the corrosion products listed in number 1.

Several conditions associated with the design and location of CR3 may have contributed to the amount of fouling in the generators. CR3 is the only B&W plant that is located near and uses sea water for condenser cooling. It is 1 of only 2 B&W units with a copper condenser. These two conditions, when combined with condenser in-leakage, can lead to a buildup of corrosion products in the secondary systems. CR3 is 1 of only 2 B&W units using a full flow deaerator. CR3 now considers the condenser as the first line of defense in insuring the integrity of the steam generators and has issued appropriately strict operating guidelines on condenser in-leakage.

Several methods to reduce fouling were evaluated, and some of those methods were tried. Flushes and rinses, boil-offs, and ultrasonic cleaning were tried and found not to be effective. The water slap procedure was somewhat effective, but improvements were needed to increase its effectiveness. Mechanical modifications to bypass some of the downcomer flow were studied but found not to be practical. The best solution seemed to be chemical cleaning, which was still under development.

In April, CR3 applied for and was granted a Technical Specification change to allow operating with a downcomer level of 96%. This permitted operation at 100% power. Analysis done by the utility and confirmed by the commission showed that there was no significant effect on the steam generator superheat and that the assumptions made in the safety analysis concerning the steamline break inventory were still valid.

12.3.4 Oconee Units 1,2, and 3

Once-through steam generators at Oconee Units 1 and 2 have been experiencing the same increased downcomer levels as those at other B&W units. Unit 3 does not have the same problem with fouling. At 100% power the levels are remaining relatively constant at approximately 70%. It is believed that better chemistry and cleanliness control in Unit 3 have resulted in elimination of the fouling problems experienced in the other two units.

In 1979, debris had been found in the "1B" steam generator at several locations, including the 9th and 14th tube support plates and the lower tube sheet. Analysis of the debris removed from the OTSG had shown the material to be predominantly iron oxide, with layering of hardness chemicals and traces of other elements. At the time this debris was thought to have contributed to tube defects that were occurring in the same vicinity. Since the evidence at the time pointed to the debris as a necessary factor for the occurrence of the defects, action was recommended to remove the debris by chemical cleaning the steam generators.

Prior to the October 1983 outage on Unit 2, the OTSG levels were as follows: "A"-67%, "B"-76%. During the outage an unsuccessful attempt was made to clean the "B" OTSG using sonic energy transmission with small nitrogen injectors. After the outage the OTSG levels were: "A"-77% and "B"-77%. Downcomer levels continued to rise until the June 1985 outage. At this time power was limited to 70% due to a high level in the "A" OTSG (86%). During the outage a combination of "water slap" and sludge lancing removed 147 lbs of debris. This allowed 100% power operation with the "A" OTSG level at 88%.

During a February 1986 outage on Unit 1, an improved water slap procedure was used in combination with sludge lancing. The lancing was performed both before and after the water slap procedure. A total of 600 lbs of debris was removed from both steam generators. This resulted in a small decrease in operating levels after the outage. Although somewhat effective in restoring levels, these procedures were not seen as the long-term solution to the fouling problem.

During the most recent outages on Units 1 and 2, chemical cleaning was performed on both generators in each unit. This was the first time chemical cleaning had been used on once-through steam generators. The results of this process are discussed in Section 12.4.5.

12.4 Once-Through Steam Generator Cleaning Methods

12.4.1 Pressure Fluctuations

The object of inducing pressure fluctuations is to redistribute the particulate matter in the steam generator in order to change the flow resistance. If areas of high concentrations of particulates could be redistributed to form a more even concentration across the generator, then the flow resistance would decrease and downcomer levels would in turn drop. The pressure fluctuations would be induced by up- and downpower maneuvers, by turbine throttle/bypass valve operation, and by planned reactor trips.

The NRC staff, in NUREG 1231, stated that these were short-sighted solutions that resulted in unnecessary plant transients and challenges to safety systems. These also proved to have little or no effect on the operating levels in the steam generators.

12.4.2 Controlled Boil-off

This method attempted to break loose some of the built up material on the tubes and broached openings by violent boiling action in the affected areas. When this method is employed the plant is in a shutdown condition. Steam generator level is lowered to the vicinity of the affected area. The agitation produced from the boiling in the area was expected to remove some of the particulate matter, reducing the flow resistance and decreasing downcomer level. This method proved to be ineffective in reducing downcomer levels.

12.4.3 Sludge Lancing

The use of this method requires entry into the steam generators. This results in some operational exposure to personnel. Water is introduced into the steam generator through spray nozzles, typically delivering about 65 gpm at 3000 psig. This high pressure spray knocks the particulate matter off the tubes and broached openings. The matter collects in the lower part of the generator with the water and is pumped to an external collecting and filtration system. The water is then returned to the generator for reuse. Two types of lancing mechanisms are used. The bundle lance mechanism, Figure 12-6, consists of a manifold of spray nozzles that is inserted into the generator between the shell and the tube bundle shroud. The water is sprayed into the tube region through access windows in the shroud. The particulate matter is then swept toward the inspection lanes. The lane lancing mechanism is then used to sweep the matter from the generator. Sludge lancing has removed anywhere from 80 to 600 lbs of material from the generator when it is used. Lancing is often used in conjunction with other types of cleaning such as water slap and chemical cleaning.

12.4.4 Water Slap

The water slap process development was a coordinated effort between MPR, Duke Power, Florida Power Corporation, and Arkansas Power and Light. Eight nitrogen injectors located on the lower handholes and manway injected 168 in^3 of nitrogen into the OTSG. The injection of high pressure nitrogen forced the water level to rise rapidly and impact the bottom of the tube support plate as the nitrogen bubbles expanded, hence the name, water-slap. This impact resulted in localized pressure forces great enough to break up and remove some of the deposits. The first time this process was used, it allowed a unit that was previously limited to 70% power to return to full power. Water slap, on the average, has removed 400-600 lbs of particulate matter from the steam generators each time it was used. An improved process is now in use. The major differences include larger injectors (350 in^3) and a surge volume, which reduces the shock load to the steam generators by acting as an absorber. Coupled with sludge lancing, this process provides a mechanical means of cleaning the OTSGs that will allow operation with reduced water levels.

12.4.5 Chemical Cleaning

Chemical cleaning has been discussed as a possible steam generator cleaning method since the late 1970's. This cleaning process had prompted several questions by the NRC staff concerning the affects of the cleaning solution on the steam generators. The process had been used for quite some time by the fossil plants in cleaning their boilers. The Electric Power Research Institute (EPRI) has been conducting tests concerning chemical cleaning and found it a highly effective method for sludge removal. Their test results showed it to remove 100% of iron sludge and 99% plus of copper sludge. The corrosion levels caused by the solution were found to be satisfactory. The process studied was generic and not specific to power plant generators.

The steam generator owners group began working with EPRI to develop a process related to power plant steam generators. Additionally, B&W, along with Duke Power Company and Arkansas Power and Light, began working on a process specifically designed for once-through steam generators. The final approved solution consisted of the following:

1. 15% EDTA (Ethelyne Diamine Tetra-Acetic Acid)
2. 1% Hydrazine
3. 1% CCI-80/1 Corrosion Inhibitor
4. pH 7 (adjusted with ammonium hydroxide)

The cleaning process consisted of maintaining the generator at 200°F, and flushing the generator with the solution for 9 cycles. The number of cycles can vary depending on the samples taken. When the flushing was finished the generator was rinsed with a solution of 300 ppm Hydrazine at a pH level of 10.2. It was then allowed to soak in this solution for some time period at 200°F. The generator was then cooled down.

During this process the OTSGs were carefully monitored for corrosion. Electrodes mounted in the OTSGs supplied signals to a field corrosion monitor to check for general and galvanic corrosion. The first generators cleaned at Oconee showed little or no corrosion; therefore, the monitoring of the second unit generators was not as extensive. The generators were carefully watched during their subsequent return to power.

The following table shows the amounts of material taken from the OTSGs at Oconee during the chemical cleaning process:

Table 12-2 Oconee Chemical Cleaning Results

OTSG	Expected(lbs)	Actual(lbs)
1A	3300	3400
1B	4600	3400
2A	4700	4100
2B	3900	4737

After chemical cleaning, Oconee Unit 1 returned to power and reached 100% power with a downcomer level of 53%. additionally, Unit 2 steam generators were sludge lanced following the chemical cleaning, and an additional total of 1200 lbs of matter was removed from the OTSGs.

12.5 Summary

Babcock and Wilcox (B&W) nuclear steam supply system once-through steam generators (OTSGs) have experienced secondary side fouling which has caused operation with high operating range levels and power output limitations. These high levels have made the affected plants susceptible to steam generator overfill events and have contributed to plant trips due to minor and moderate feedwater overfeeding. The degree of fouling and the subsequent limitation of power have been totally plant dependent and seem to be a function of the secondary side chemical controls. Metal oxide deposition on the lower tube support plates appears to be the cause of the increasing secondary side steam generator level.

Several methods have been tried to clean the secondary side of the steam generators in order to reduce the metal oxide content. These methods include pressure fluctuations, water lancing, water slap and chemical cleaning. At present, chemical cleaning has produced the best results.

12.6 References

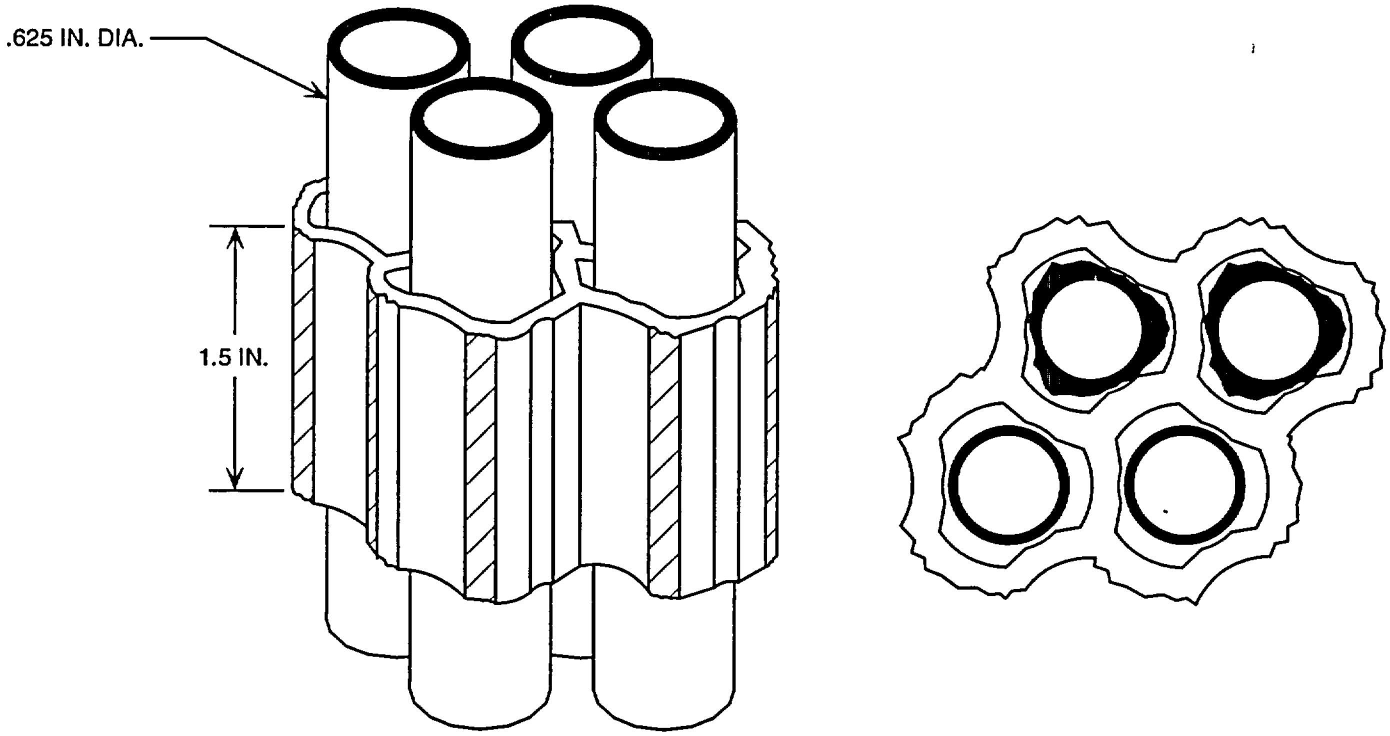
1. U.S. Nuclear Regulatory Commission, NUREG 1231, "Safety Evaluation Report related to Babcock & Wilcox Owners Group Plant Reassessment Program", November 1987.

2. Summary of Meeting with AP&L Concerning the Chemical Cleaning Program for ANO-1 Once-Through Steam Generator (OTSG).

3. Power Plant Experiences Manual, Items V.D.338 and V.D.434

4. Letter from H.D. Hukill, Jr, GPU Nuclear, to Document Control Desk U.S. Nuclear Regulatory Commission, "OTSG Fouling - Long Term Plan", August 24, 1987.

5. Presentation to B&W Counterpart meeting, "Tube Fouling Experience and Water-Slap Procedure", May 1986.



Tube Support Plates, Breached
Openings
for Flow Between Plates and Tubes.

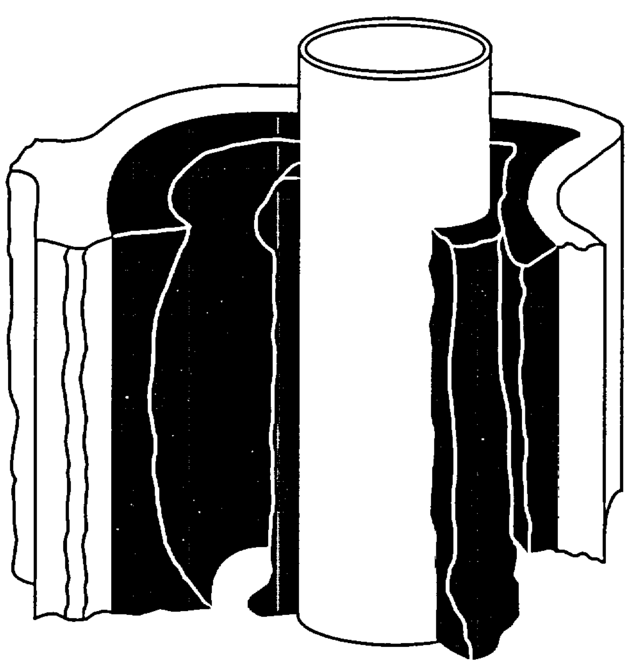


Figure 12-1 Typical OTSG Fouling

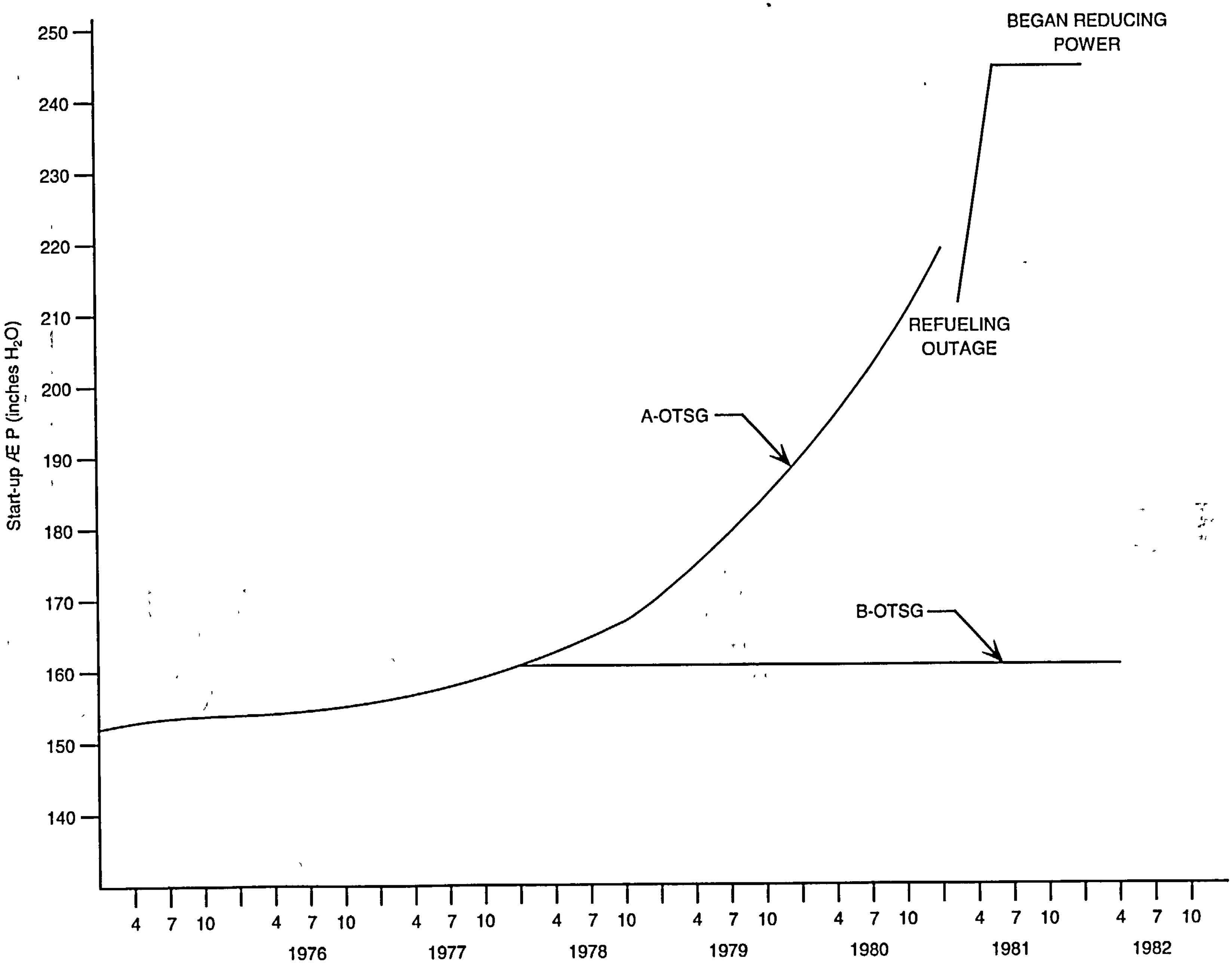


Figure 12-2 ANO-1 Operating Levels

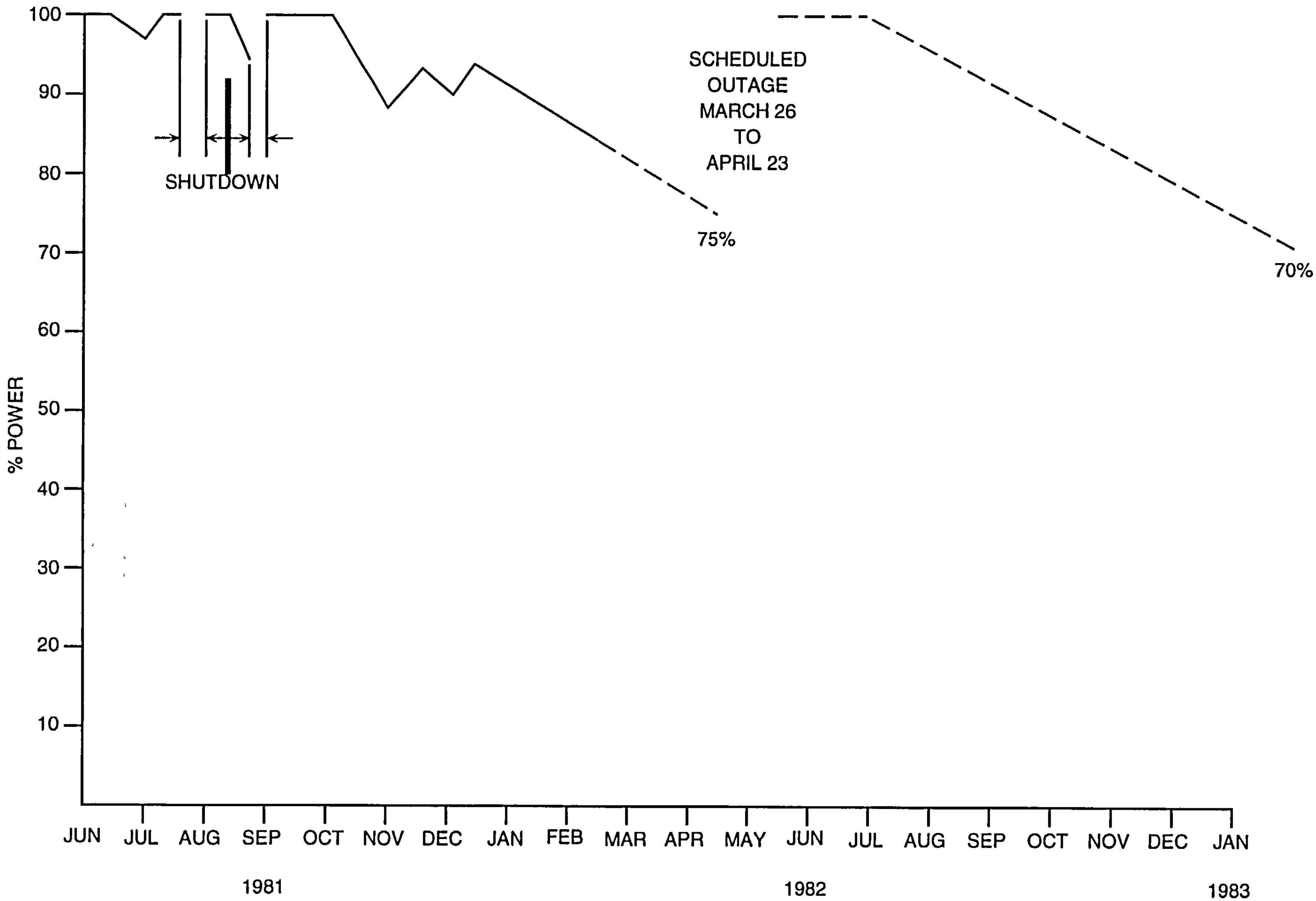


Figure 12-3 ANO-1 Power

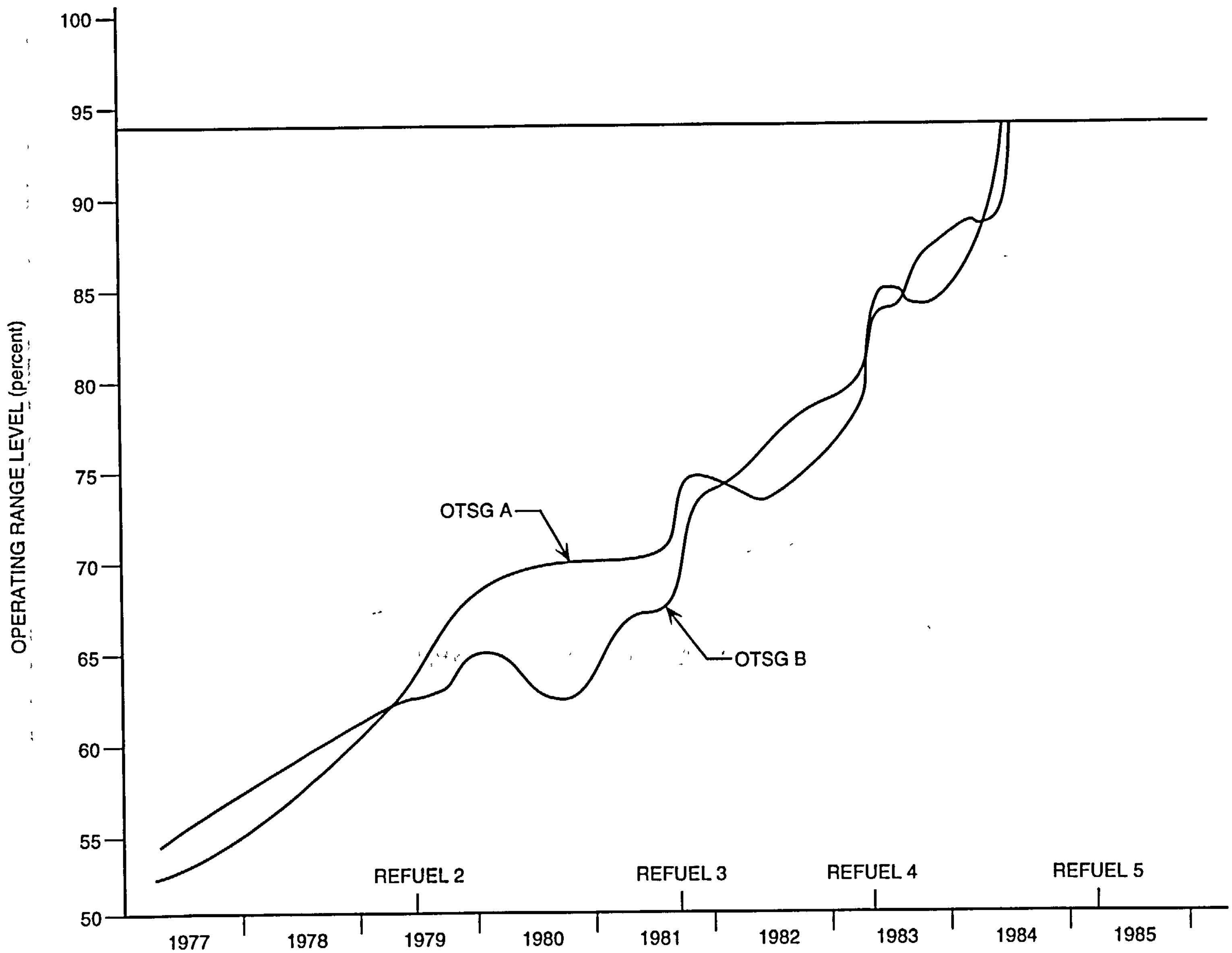


Figure 12-4 Crystal River Unit 3 OTSG Operating Range History

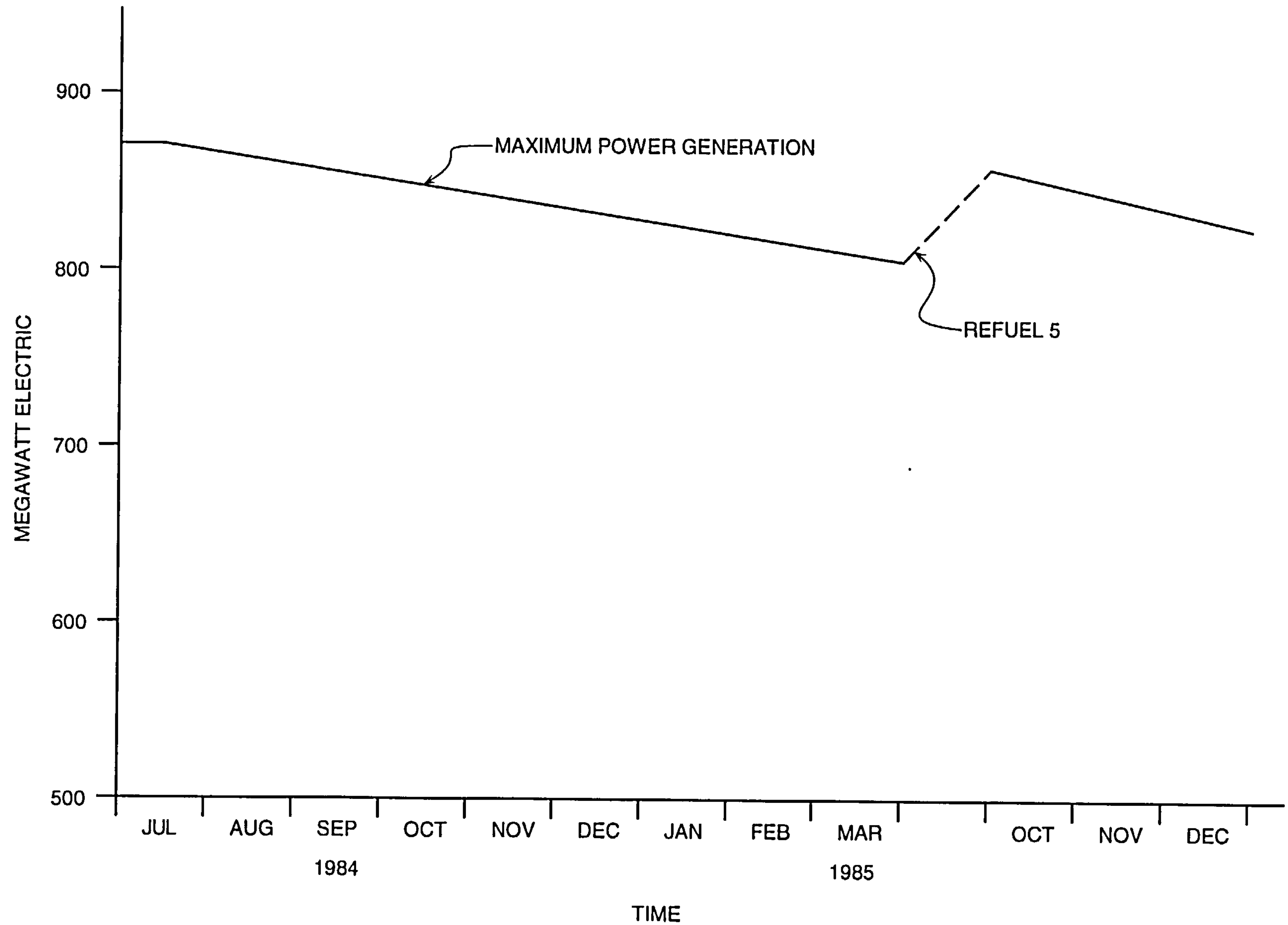


Figure 12-5 Crystal River Unit 3 Power History

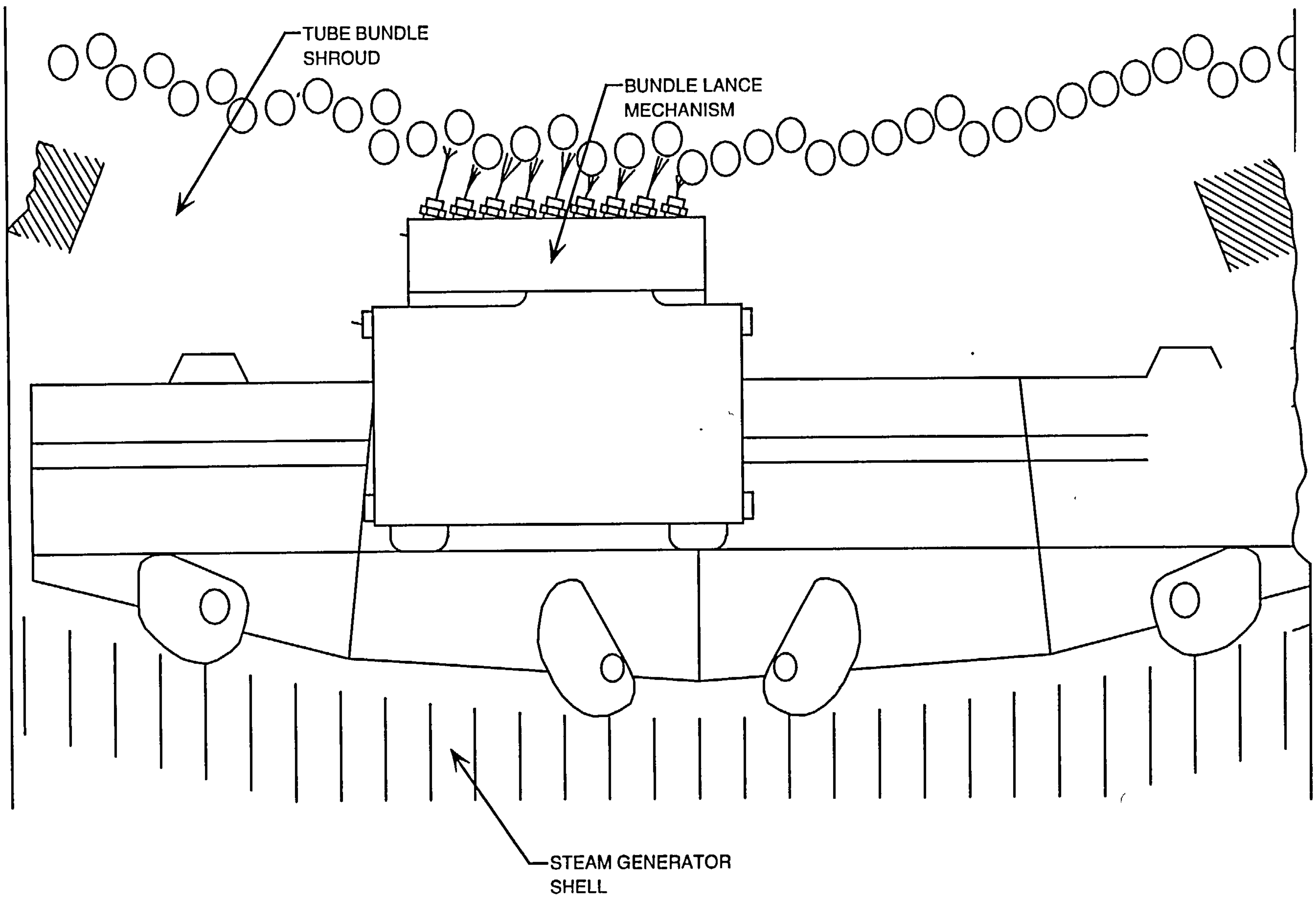


Figure 12-6 Bundle Lance Mechanism